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BEFORE THE ARIZONA CORPORATION COMMISSION

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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

Arizona Corporation Commission
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INITIAL POST-HEARING BRIEF
OF
ARIZONA INVESTMENT COUNCIL

APRIL 25, 2016

I. INTRODUCTION

In its application, UNS Electric, Inc. ("UNS Electric" or "the Company") asks the Arizona Corporation Commission ("Commission") to approve changes to its rate design and net metering tariffs to help ensure that all customers pay an equitable share of the fixed, ongoing costs of providing safe and reliable electric service. Under the current two-part rate design and net-metering tariffs, utility rates are decidedly non-neutral and biased in favor of Distributed Generation ("DG") customers who reduce their energy consumption without reducing their use of the electricity grid. These customers avoid paying a significant portion of UNS Electric's fixed costs—costs which are thus shifted to other non-DG customers. UNS Electric's proposed changes will eliminate the customer and technology biases inherent in the current rate structure and move it towards the ideal: a rate design that is "neutral, agnostic, and unbiased towards the technology and lifestyle choices of customers." (Exhibit S-16 (Broderick Rate Design Direct) at 26.)

UNS Electric also proposes, but actively opposes, a buy through rate—Rate Rider 14. The original buy-through rate program, Arizona Public Service Company's ("APS") AG-1 experimental rate rider, was implemented as a four year pilot program as part of a settlement agreement that was to be fully vetted and analyzed in APS's next rate case (to be filed June of this year). Although that pilot program has yet to be evaluated, evidence presented in this case demonstrates that the buy-through rate program has serious flaws that impairs the recovery of millions of dollars of program costs and results in cost shifts to other customers and stakeholders. The fate of the buy-through program will be determined after the Commission has the opportunity to examine that data and decide whether such program is in the public interest and, if so, how the program can be redesigned to address its deficiencies. It is simply premature to implement such a program in the UNS Electric service territory now.

On the other hand, AIC supports UNS Electric's proposed Rate Rider 13, the proposed Economic Development rate. UNS Electric's service territories have been slower to recover from the economic recession than other parts of Arizona, and encouraging economic development through incentives like discounted electricity rates will facilitate that recovery—to the benefit of the Company and all of its customers.

DISCUSSION OF ISSUES

A. Mandatory Residential Demand Rates

> ***"Metering and communications technology improvements, DG penetration, and recent regulatory issues have made [the] adoption [of demand charges] for residential and small general service customers possible, appropriate, timely, and even necessary."***
>
> - Thomas M. Broderick, on behalf of Arizona Corporation Commission Staff (Exhibit S-16 (Broderick Rate Design Direct) at 2.)

1. Residential Demand Rates Are in the Public Interest, and Making Them Mandatory for All Customers Maximizes Key Public Policy Objectives.

AIC strongly supports Staff's proposal that all UNS Electric customers be placed on a three-part residential demand rate, designed as described in the Company's testimony. (*See, e.g.*, Exhibit UNSE-29 (Dukes Rebuttal) at 2-13.) Such a rate design will provide the foundation of a regulatory environment that supports both the maintenance of and continued investment in our indispensable utility infrastructure, as well as the development of sustainable third party business models. The energy landscape is evolving, and customers are being offered the opportunity to adopt new technologies that allow them to manage their energy use on their side of the electric meter—technologies such as rooftop solar units, energy storage devices, smart in-home thermostats, electric vehicles and the like. (*See* Exhibit APS-6 (Meissner Direct) at 4.) These technologies are changing *how* customers use the electric grid, but not *whether* they do so. (*Id.* at 4-6.) As AIC witness Daniel Hansen testified, even if you are a solar DG customer, "you are probably using the grid every second because you are either producing more than you need and sending it back, or you are using more than you are producing and you are pulling some out." (Hansen Hearing Testimony, Tr. at 1689:21-25.) Arizona's grid infrastructure thus remains fundamental to the provision of reliable, high-quality, cost-effective electric service for everyone.

To serve the public interest, a utility rate design must therefore both allow the utility the opportunity to recover its investment in the power grid (its fixed costs of service) while also allowing customers who choose to install cost-effective behind-the-electric meter technologies the opportunity to save money. (*See, e.g.*, Exhibit UNSE-31 (Jones Direct) at 12-13, 36; Exhibit APS-6 (Miessner Direct) at 10.) Unfortunately, today's two-part energy rate does not do the trick. (*See* Exhibit S-16 (Broderick Rate Design Direct) at 3-5.) Under a two-part rate regime, where most of a utility's fixed costs are recovered through a volumetric energy charge, a customer who offsets his electric bill with distributed generation is paid too much for the energy his system produces—the credit he gets includes both costs that he avoids (fuel, for example) and costs that he doesn't avoid (the poles, meters, wires, etc.). (*See* Exhibit AIC-D (Hansen Surrebuttal) at 21.) The result is that, absent decoupling or a similar rate tool, the utility loses the opportunity to fully recover its fixed costs in between rate cases, and an intra-class cost-shift occurs every time rates are reset. (*See* Exhibit AIC-C (Hansen Direct) at 16-17.) This is not a sustainable rate design.

The proposed three-part demand rate goes a long way towards resolving those issues because it provides a price signal to customers that offers value on both sides of the electric meter. (*See* Exhibit AIC-C (Hansen Direct) at 4-5.) A demand charge lowers the energy charge by moving some (but in this case, not all) of the fixed costs to a demand charge. (*See* Exhibit UNSE-3 (Hutchens Direct) at 14.) A demand charge is not a fixed charge, but recovers fixed costs through a per kW rate. (*See* AIC-C (Hansen Direct) at 3-4.) This design incentivizes customers to smooth their load and become much more efficient for the utility to serve—something that a simple volumetric rate does not do. (*Id.* at 6-7.) Whether the customer smooths load through efficiency, battery storage, load controllers, or through other technologies, both short- and long-term benefits result: monthly bill savings in the short-term (through reduced demand charges) and the deferral or elimination of new infrastructure investments to meet peak demand (stabilizing rates over the long-term). (*Id.*) A demand charge is agnostic as to the technology that customers use to achieve those benefits, allowing all cost-effective behind-the-meter technologies to compete against one another in the energy market fairly, with the resulting societal benefits. (*See* Exhibit S-16 (Broderick Rate Design Direct) at 6-7.) With the proliferation of advanced metering, utilities are now able to gather and share demand information with their customers. As Staff witness Howard Solganick acknowledged, it is now time to use that information to align rates with costs and send the proper price signals to consumers, "otherwise, I should be arguing that utilities are imprudent for building a metering system and then wasting the data." (Solganick Hearing Testimony, Tr. at 2748:11-14.) For all of these reasons, AIC wholeheartedly agrees with Staff's observation that "a three-part rate structure is more reflective of UNSE's costs of service and *the sooner a migration occurs the better for all.*" (Exhibit S-16 (Broderick Rate Design Direct) at 2 (emphasis added).)

2. Other Proposed Rate Designs Are Inferior to Residential Demand Rates at Achieving Key Public Policy Objectives.

Various intervenors in this case have suggested alternatives to the proposed three-part demand rates, including a minimum bill provision, Time-of-Use ("TOU") energy charges, and optional rates for DG customers. (*See* Exhibit AIC-D (Hansen Surrebuttal) at 7) (summarizing alternative proposals). However, none of these alternatives can effectively address the fundamental flaws in the current rate design and achieve key public policy objectives as well as the proposed three-part rate does, because "they provide price signals that aren't as closely related to costs." (Hansen Hearing Testimony, Tr. at 1692:2-3.)

a. A Minimum Bill Does Not Achieve Public Policy Objectives as well as a Three-Part Demand Rate.

One alternative that has received some level of support from certain intervenors is a continuation of the two-part rates in conjunction with a minimum bill provision. (*See*, *e.g.*, Exhibit RUCO-5 (Huber Direct) at 8; Exhibit TASC-19 (Fulmer Direct) at 24.) Under this proposal, customers would be charged the greater of the minimum bill amount or their bill under the standard rates (the basic service charge + energy consumed **x** the energy rate). (*See* Exhibit AIC-D (Hansen Surrebuttal) at 9.) A minimum bill provision, however, cannot accomplish the same equitable and public policy objectives as a three-part demand rate, for several reasons.

First and most importantly, a minimum bill provision fails to address the fundamental problem with the current rate design, which is that it does not accurately reflect customer demand costs. (*Id.* at 9-10.) A one-size-fits-all minimum bill provision would apply to all customers regardless of their usage, demand, or load factor, and perpetuate the current problems with intra-customer cost-shifting. (*Id.*) A minimum bill provision would therefore merely replace the current cost-related inefficiencies with different ones.

Second, this lack of correlation would continue to misalign price signals and customer behavior. A minimum bill provision does not reward reductions in demand or improvements in load factor and eliminates nearly all customer ability to control or reduce electric bills. (*See* Exhibit APS-4 (Faruqui Surrebuttal) at 4; Exhibit APS-7 (Miessner Surrebuttal) at 15-17.) As Commission Staff noted, this "would be highly unfriendly to new technologies and a major step backwards." (Exhibit S-16 (Broderick Rate Design Direct) at 9.)

Third, to sufficiently recover costs and minimize cross-subsidies, any minimum bill provision would need to be tiered according to each home's usual demand and set at much higher rates than current service charges. (Exhibit APS-7 (Miessner Surrebuttal) at 10-14.) In practice, for the minimum bill to contribute to recovery of UNS's fixed costs, the benchmark would need to be higher than the current service charges and variable rates for energy consumed each month, and much higher than any benchmark proposed by minimum bill provision proponents. (*Id.* at 11.) For example, proponents of the minimum bill provision suggest benchmarks ranging from $12.00 to $25.00. (Exhibit RUCO-5 (Huber Direct) at 11; Exhibit APS-7 (Miessner Surrebuttal) at 14.) But, as APS witness Chuck Miessner illustrated, to be a viable alternative to the three-part demand rate in terms of contributing towards fixed costs, minimum bills would need to be in the range of $30 for small homes, $70 for medium-sized homes, and $150 for large homes. (Exhibit APS-7 (Miessner Surrebuttal) at 14.) Proponents of this alternative will certainly oppose any minimum bill that is set high enough to recover all customer- and demand-related costs. (*See, e.g.*, Exhibit Vote Solar-7 (Kobor Surrebuttal) at 68-69) (noting that Vote Solar would support a minimum bill only if it "were to remain small"). As described by AIC witness Daniel Hansen, the proposed minimum bill is like saying, "we have got a $100 problem, . . . so here is $10, that's the sort of magnitude we are talking about." (Hansen Hearing Testimony, Tr. at 1681:18-20.)

b. Time of Use Rates Without a Demand Component Do Not Achieve Public Policy Objectives as Well as a Three-Part Demand Rate.

Several intervenors also proposed Time-of-Use ("TOU") energy rates as an alternative to three-part demand rates. (*See, e.g.*, Exhibit Vote Solar-7 (Kobor Surrebuttal) at 60.) AIC supports Staff's proposal to include a TOU component as part of a new three-part rate design to align rates with the costs of energy consumption over time. (See Exhibit AIC-D (Hansen Surrebuttal) at 8.) However, TOU energy rates are not by themselves a viable alternative to a three-part demand rate because they cannot adequately reflect costs that do not vary over time and with consumption, such as infrastructure and capacity costs. (*Id.*; Exhibit APS-7 (Miessner Surrebuttal) at 15-16.) Instead, stand-alone TOU rates must rely on a volumetric kWh charge to recover fixed costs. (*Id.*; Exhibit APS-4 (Faruqui Surrebuttal) at 4-5.) As the Commission recognized when it approved three-part rates for APS customers, basing residential rates primarily on each customer's kWh energy consumption "ignores the fact that the cost of providing electric services is increasingly a function of the demand for electricity placed on the system rather than the total power consumed." (*See* ACC Decision No. 51472 (Oct. 21, 1980), at Finding of Fact 1.) Consequently, a TOU energy rate without a demand component does nothing to resolve the problem associated with recovering demand-related costs through energy charges, because DG and other low load factor customers will continue to pay less than their fair share of demand-related costs. (*See* Exhibit AIC-D (Hansen Surrebuttal) at 8; Exhibit APS-7 (Miessner Surrebuttal) at 16.)

Moreover, because TOU rates do not reflect demand-related costs, they do not incentivize customers to reduce demand nor adopt technologies that are focused on reducing the home's electrical infrastructure requirements. (Exhibit APS-7 (Miessner Surrebuttal) at 16; Hansen Hearing Testimony, Tr. at 1657:9-10 ("A time-of-use rate doesn't directly give customers an incentive to reduce their bill to demand.").) For these reasons, TOU energy rates by themselves are not a viable alternative to three-part rates.

c. RUCO's Rate Design Proposals Do Not Achieve Public Policy Objectives as Well as a Three-Part Demand Rate.

Similarly, intervenor RUCO's rate design proposals do not address the fundamental flaw with the existing rate design. Objecting that UNS Electric's three-part rates "lack[] optionality for customers," RUCO witness Lon Huber instead proposed that UNS offer three optional rates to DG customers:

(1) the "Non-Export Option," under which DG customers could select any of the Company's standard rates but would not be allowed to export power to the grid;

(2) the "Advanced DG TOU Option," under which DG customers would pay a three-part rate consisting of a minimum bill, a flat base energy rate ($0.084/kWh), and a peak-hours demand charge ($19.50/kWh incurred between 2 and 8 p.m.) and could export power to the grid and receive credit dependent upon whether the customer exchanges Renewable Energy Credits ("RECs") with the Company; and

(3) the "RPS Bill Credit Option," under which DG customers could select any of the Company's standard rates and receive a credit that is based on the amount of renewable capacity added over time (starting at $0.11/kWh), but customers must exchange RECs with the Company.

(Exhibit RUCO-5 (Huber Direct) at 11.) In practice, however, RUCO's proposal would neither offer increased optionality nor address the demand-related cost problems inherent in the current rate structure. Instead, the proposal would perpetuate the current two-part rate system. (*See* Exhibit AIC-D (Hansen Surrebuttal) at 12.)

Both the Non-Export Option and the RPS Bill Credit Option would allow DG customers to choose any of the Company's traditional rates—i.e., two-part rates. (*Id.*) As already explained, DG customers benefit (to the detriment of other UNS Electric customers) from the two-part rates because they avoid paying their fair share of demand-related costs under such rates. Accordingly, DG customers have no incentive to select a three-part demand rate under the Advanced DG TOU Option, because they pay less (albeit unfairly) under the two-part rate. (*Id.*) AIC witness Daniel Hansen provided a detailed comparison of the costs of the RPS Bill Credit Option and Advanced DG TOU Option for a variety of UNS Electric customers, ranging from those who use no DG to those who get at least 50% of their energy needs from DG and actively manage demand. (*Id.* at 14-16.) As Mr. Hansen explained, the Advanced DG TOU Option would increase customers' bills under each scenario—even in the case of DG customers who actively manage their demand. (*Id.* at 15) (illustrating that customers' bills would be anywhere from 19% to 290% higher, depending on usage and the option chosen). Practically speaking, this means that virtually no DG customers will select the Advanced DG TOU Option and voluntarily pay more for electric services, given the other options available.

Further, in practice, RUCO's proposal will not provide additional "optionality" because only the RPS Bill Credit Option makes economic sense for DG customers. While both the Non-Export Option and the RPS Bill Credit Option allow DG customers to continue under the traditional two-part rate, the RPS Bill Credit Option allows DG customers to get paid for excess generation under a two-part rate, while the Non-Export Option does not. (*Id.* at 13.) No rational customer would select a rate that pays nothing for excess generation rather than something, when the rates are otherwise equal. Indeed, RUCO's own witness admits that the Non-Export Option "will likely not be very popular among DG customers," while the RPS Bill Credit Option will be "the most popular rate." (Exhibit RUCO-5 (Huber Direct) at 23-24.)

AIC certainly appreciates RUCO's willingness to propose alternatives. However, RUCO's rate proposals would simply perpetuate the status quo and therefore do not present a viable alternative to a three-part demand rate for residential electricity.

3. Residential Demand Rates Encourage Conservation.

AIC supports the Company's proposed three-part demand rate in large part because it provides accurate price signals that incentivize customers to behave in a more energy efficient manner, both with respect to energy consumption and to demand. Some intervenors suggest that because the three-part rate structure lowers the volumetric rate, customers will have *less* incentive to conserve energy. (*See* Exhibit WRA-1 (Wilson Direct) at 9; Exhibit TASC-19 (Fulmer Direct) at 21, 24.) For example, TASC witness Fulmer argued that DG customers would react to a three-part demand rate by consuming more power rather than less, because this is the "easiest and primary way that customers can improve their load factor." (Exhibit TASC-19 (Fulmer Direct) at 20-21.) Such an argument is absurd, conflating a reduction in the average rate paid per kWh with a reduction in the customer's bill. (*See* Exhibit AIC-D (Hansen Surrebuttal) at 19.) A customer who holds demand constant while increasing usage would pay a reduced average price per kWh, but the customer's total bill would also increase. (*Id.*) It is highly unlikely that customers will react to the demand charge by increasing consumption and raising their electric bill, as opposed to reducing their peak demand (nor would the Company encourage customers to manage their load factors in this way).

In fact, the opposite is true, because three-part demand rates provide additional and different conservation opportunities to residential customers. (*See* Exhibit UNSE-30 (Dukes Rejoinder) at 4-8.) Under a two-part rate, customers can reduce their bills only by reducing electricity consumption. (*Id.*; Exhibit APS-7 (Miessner Surrebuttal) at 17.) By contrast, under a three-part demand rate, a customer can reduce his or her bill by reducing consumption, reducing demand, or both. (*Id.*) Demand-related efficiency is particularly important because it can reduce or negate the need for significant infrastructure investment going forward. (*See* Exhibit AIC-C (Hansen Direct) at 6-7; Exhibit APS-1 (Brown Surrebuttal) at 24-25.) Focusing only on consumption-related efficiency ignores this substantial component of the utility's overall costs, and will cost customers more in the long run. Further, in APS's 30-plus years of experience with demand rates, residential customers on a three-part rate have improved efficiency in both regards by reducing demand and total electricity consumption. (*See* Exhibit APS-6 (Miessner Direct) at 7-8.) Thus, both theoretically and in practice, demand charges do not stifle conservation but incentivize it.

4. Residential Demand Rates Will Not "Kill the Solar Industry."

Some intervenors object to the demand charge because they contend, without any data-driven evidence, that such a rate design will hurt the solar industry. (*See, e.g.*, Exhibit TASC-19 (Fulmer Direct) at 15.) But, as testimony in this case shows, UNS Electric's rate design proposal allows distributed generation customers to save on their bills both by avoiding the energy charge to the extent their consumption is offset by self-generation, and by moderating their demand and smoothing their load. (*See, e.g.*, Exhibit APS-3 (Faruqui Direct) at 14; Exhibit APS-1 (Brown Surrebuttal) at 4-5.) There is no logical reason why the solar industry cannot market their product given the continued savings potential. In fact, evidence in the record suggests that such a business model is already being rolled out in the Salt River Project service territory, which has implemented a three-part demand rate for DG customers. (*See* Exhibit AIC-C (Hansen Direct) at 11 & n.8; Exhibit AIC-H; Exhibit APS-10.)

Perhaps more fundamentally, the Commission's ratemaking obligation is to balance the interests of the utility and its customers in a manner that serves the public good—not to prop up the economic well-being of a single industry be means of a steep embedded subsidy paid by utility ratepayers. (*See* Ariz. Const. art. XIV, sec. 12.)

Notwithstanding that solar industry profits are not in and of themselves a valid consideration for the Commission to consider when setting rates, the evidence suggests that demand charges are an important step in ensuring the long-term viability of the solar industry. (*See, e.g.*, Exhibit APS-1 (Brown Surrebuttal) at 22-25.) In the long term, to be fully sustainable, solar energy needs to be competitive on both a price and qualitative basis. As the evidence has demonstrated, solar DG is expected to grow throughout Arizona. That is a good thing, but the more solar DG grows without a change in the underlying rate structure, the more of a burden the current cross-subsidies will become. (*See, e.g.*, *id.* at 31; Exhibit UNSE-28 (Dukes Direct) at 23.) As APS witness Dr. Faruqui testified, "we have to modernize the rate structure as much as we are modernizing the technologies in the customers' homes. Otherwise, we are going to have cross-subsidies multiplying with every passing year." (Faruqui Hearing Testimony, Tr. at 3048:4-8.) Further, as evidenced by other states' experiences, the politics and practicalities of getting the pricing right become increasingly difficult as more and more people become invested in solar DG systems on the basis of a severely skewed and economically perverse tariff. (*See* Exhibit APS-1 (Brown Surrebuttal) at 31.)

The demand charges proposed by UNS Electric will provide price signals that will enhance the productivity and efficiency of solar DG because they reflect the actual costs of providing energy to customers. (*Id.* at 23-25.) By removing misaligned subsidies that artificially inflate the cost of DG solar and exposing solar energy to competitive market forces, solar companies will be incentivized to update their business models and provide greater opportunity for consumers. (*Id.* at 22-23.) These changes mean that "[i]n the long run, solar energy will have a much brighter future and will be better assured of finding its place in the mainstream of energy resources." (*Id.* at 23.)

Intervenors Vote Solar and TASC nonetheless vigorously protest demand charges in favor of continuing an outdated and unsustainable business model. The perversity of Vote Solar and TASC's arguments is that they are detrimental to the long-term well-being of the entire solar industry. This is well illustrated by Ms. Kobor's argument that demand charges should not be implemented because "enabling technologies" that could help customers manage demand are "uncommon, costly to implement, and have not achieved widespread adoption." (*See* Exhibit Vote Solar-6 (Kobor Direct) at 35.) In other words, Ms. Kobor argues against demand charges (which would incentivize investment and innovation in demand-side technologies) because currently, demand-side technologies are not prevalent or widespread. (*See* Exhibit APS-1 (Brown Surrebuttal) at 25-26.) This position is not only circular, but it is guaranteed to stunt growth and innovation in a way that is harmful to the long-term sustainability and modernization of the renewable energy market.

What is notable about demand rates is that they have widespread support across a variety of groups, from government agencies and utilities to environmental groups—indeed, even the nationally-recognized Natural Resources Defense Council has issued a statement endorsing the use of demand charges. (*See* Exhibit APS-1

(Brown Surrebuttal) at 23-24.) Tellingly, the most vocal opponents of demand charges, both nationally and in this case, are those who stand to lose the inequitably high profits associated with the existing net metering regime in combination with two-part energy rates—rooftop solar companies. The Commission should not allow the short-term profitability of a small number of companies to override the long-term sustainability of solar energy, not to mention fairness to all UNS Electric ratepayers. As APS witness Ashley Brown aptly observed, "[i]n fairness to both DG and non-DG customers alike, it is important to get rate signals correct and sustainable as soon as possible." (Exhibit APS-1 (Brown Surrebuttal) at 31.)

5. Residential Demand Rates Will Not Operate as a Fixed Cost.

Finally, intervenor Vote Solar and others contend that residential demand charges "would likely function as an additional fixed charge for most residential and small commercial customers because they lack the tools and understanding to effectively respond to the demand charge price signal." (Exhibit Vote Solar-6 (Kobor Direct) at 30.) There are two problems with this argument. First, Vote Solar offers no evidence whatsoever to suggest that customers will be unable or unwilling to adjust their demand in response to price signals. (*See id.*) In fact, the evidence presented throughout this case suggests the opposite. APS witnesses testified that over 117,000 APS customers have elected to take service on a voluntary demand charge, and 60% of those customers reduced their demand after switching to the three-part rate. (*See* Exhibit APS-4 (Faruqui Surrebuttal) at 7; Exhibit APS-6 (Miessner Direct) at 7.) Further, APS witness Ahmad Faruqui cited no less than four studies that show customers respond not only to changes in price signals generally, but to demand charges specifically. (*See* Exhibit APS-3 (Faruqui Direct) at 15.) These studies are timely, relevant, and focus precisely on the issue raised by intervenors here, unlike the studies demand charge opponents cite, which did *not* focus on customer response to demand charges, and in some cases, not even on customer response generally. (*See* Exhibit APS-4 (Faruqui Surrebuttal) at 9-10.)

Second, even assuming that some customers would not understand how to reduce their demand initially with a demand charge, it is still possible for them to do so in the future as they gain understanding. (*See* Exhibit APS-4 (Faruqui Surrebuttal) at 8-9.) By contrast, several alternatives proposed by intervenors involve *increased or additional fixed charges*, which deprive customers of the opportunity to reduce their bills below the minimum charges entirely. (*See, e.g.*, Exhibit RUCO-5 (Huber Direct) at 8; Exhibit Vote Solar-7 (Kobor Surrebuttal) at 67.) Consequently, even if this "fixed cost" critique of residential demand rates were supported by the evidence, residential demand rates would still be a better choice for customers than many of the proposed alternatives.

B. Proposed Changes to the Net Metering Rules

> ***"UNS Electric's proposed [net metering changes] balance[] the concerns of energy affordability with the desire to expand Arizona's renewable generating portfolio by compensating DG customers for excess generation at a rate approximately equal to the cost of obtaining renewable power from an alternate source. This is fairer to <u>all</u> UNS Electric customers than the current net metering policies."***
>
> - Daniel G. Hansen, on behalf of Arizona Investment Council (Exhibit AIC-D (Hansen Surrebuttal) at 21.)

1. UNS Electric's Proposed Changes to the Net Metering Rule Are in the Public Interest.

Arizona's current net metering policy requires UNS Electric to buy any excess generation from a customer's distributed solar system at the full retail rate, even though it would cost UNS Electric less to produce the electricity itself or to buy the power on the wholesale market. (*See* Exhibit UNSE-26 (Tilghman Rebuttal) at 7.) The net metering rules were originally intended to incentivize early adopters of distributed solar, not to create huge subsidies that shift costs from one group of customers to another. The cost of solar systems has come down significantly since the net metering rules were first adopted, and, with the long-term extension of the federal investment tax credit at 30% (*See* Exhibit UNSE-4 (Hutchens Rebuttal) at 14), there is no need for

UNS Electric customers to pay more for distributed solar energy than it would for any other solar energy that it could procure on the market.

The Company proposes to compensate DG customers for excess energy using a Renewable Credit Rate ("RCR") that is set using the Company's most recently negotiated purchased power agreement ("PPA") for utility-scale solar as a benchmark. (*See* Exhibit UNSE-25 (Tilghman Direct) at 7.) This benchmark is a far better reflection of the cost of energy produced by distributed generation than the current retail rate. (*See* Exhibit UNSE-26 (Tilghman Rebuttal) at 7; Exhibit AIC-D (Hansen Surrebuttal) at 21.) The current retail rate overcompensates DG customers for the excess energy they produce because DG customers are credited at a per-kWh retail rate (which embeds fixed costs associated with maintenance of the distribution grid) even though DG customers do not incur these fixed costs. (*Id.*; *see also* Exhibit UNSE-2 (Dukes Direct) at 20-22.) In other words, DG customers are credited for both the costs that they avoid (e.g., fuel) and costs that they don't (the poles, meters, wires, etc.).

Neither is the Company seeking to do away with the net metering rules in their entirety. Rather, UNS Electric is proposing to change the RCR only in regards to excess energy that flows back onto the grid from the DG customer's system. (*See* Exhibit UNSE-26 (Tilghman Rebuttal) at 6.) Under the Company's proposal, DG customers will continue to receive credit at the full retail rate for every kWh of energy produced from a DG system that the customer uses. (*See id.*) For the excess energy that flows back onto the grid, using the Company's most recently negotiated utility-scale solar PPA as a benchmark provides a generous and fair rate to DG customers, while ensuring that the rest of UNS Electric's customers are not forced to pay more than the price at which UNS Electric is currently able to procure solar energy. (*See id.* at 6-7; Exhibit AIC-D (Hansen Surrebuttal) at 21-22.) It is against the public interest to require non-solar customers to pay twice the amount for solar generation from solar customers than what the Company could otherwise procure for solar. (*See id.*; *see also*

Exhibit APS-1 (Brown Surrebuttal) at 35.) AIC therefore supports the Company's proposed limited waiver from the net metering rules.

2. Sufficient Evidence Exists to Justify Compensating Distributed Solar Generation at a Price Equal to Wholesale Utility Generation.

AIC strongly supports the adoption of the Company's proposed Renewable Credit Rate because it is a fair, market-based proxy rate that appropriately compensates customers who export excess distributed solar energy to the grid. The Company proposes to compensate DG customers for excess energy production at a rate based on the Company's most recently negotiated PPA for utility-scale solar energy that is connected to the Company's or Tucson Electric Power's distribution system. (Exhibit UNSE-25 (Tilghman Direct) at 7.) The proposed value is $0.584/kWh, which is based on a recent agreement with Tucson Electric Power. (*Id.*)

While not an exact proxy, utility-scale solar prices provide a much more accurate reflection of the actual cost to produce solar energy than the retail rate. (*See* Exhibit UNSE-26 (Tilghman Rebuttal) at 7.) As already discussed, the retail rate has no relation to the value of DG and significantly overcompensates DG customers for excess energy. (*See id.*) This, in turn, means that non-DG customers must absorb these costs and pay more for solar energy than the Company could procure it for on the open market. (Exhibit UNSE-25 (Tilghman Direct) at 7-8.) Because ratepayers ultimately pay the difference between conventional and renewable energy prices, it is appropriate for net-metered customers to receive the same compensation that is available from other more cost-effective solar resources. (*Id.*)

Further, by using the most recently negotiated rate, the proposed RCR recognizes that energy prices fluctuate and thus does not lock in a higher rate than the market standard for solar DG. (*See* Exhibit APS-1 (Brown Surrebuttal) at 35.) In fact, the utility-scale solar rate is generous to DG customers, as the Company will be compensating solar DG at the same rate as it does for utility-scale solar, despite utility-scale solar being a more efficient resource. (*Id.*) And by using the price paid for a more efficient resource as a proxy, the proposal will incentivize solar DG to become more efficient and improve productivity, something that is "completely lacking in the existing retail net metering pricing model." (*Id.*) In addition, the RCR benchmark price involves an "apples to apples" comparison because it is derived from transactions involving intermittent energy resources, similar to solar DG. (*Id.* at 36.) Accordingly, the most recently negotiated utility-scale solar price is a fair and reasonable proxy that is subject to market discipline, recognizes fluctuations in the wholesale market, and prevents reallocation of capital towards less efficient resources.

Nonetheless, intervenors TASC and Vote Solar object to using utility-scale solar prices as a proxy for distributed generation on the theory that DG solar provides more benefits and thus has more value than utility-scale solar. For example, Vote Solar witness Kobor claims that DG solar is more valuable than utility-scale solar because of "the higher generation capacity value due to the geographic diversity of DG systems, potentially greater avoided distribution costs and grid services from DG, and greater local employment benefits accruing from DG." (Exhibit Vote Solar-6 (Kobor Direct) at 30.) For his part, TASC witness Fulmer highlights the even more vague "potential habitat, visual and cultural impacts" of solar DG systems versus utility-scale solar plants as a reason for treating solar DG as more valuable. (Exhibit TASC-20 (Fulmer Direct) at 4.) However, neither TASC nor Vote Solar provide any substantive evidence in support of these supposed added "values" of rooftop solar over utility-scale solar. (*See* Exhibit APS-1 (Brown Surrebuttal) at 36; Exhibit UNSE-26 (Tilghman Rebuttal) at 12.) In contrast, UNS Electric and APS witnesses provided in-depth, detailed, and relevant evidence that refutes these unsubstantiated claims of solar DG's added value.

To start, APS witness Ashley Brown and UNS Electric witness Carmine Tilghman explained well why geographic diversity does not translate to added value in solar DG. (*See* Exhibit APS-1 (Brown Surrebuttal) at 36-37; Exhibit UNSE-26

(Tilghman Rebuttal) at 12.) As Mr. Brown explained, utility-scale solar can also take advantage of geographic diversity and potentially offers even greater diversity since utilities can purchase power from distant plants, so long as they are connected to the grid. (*See* Exhibit APS-1 (Brown Surrebuttal) at 36-37). Moreover, geographic diversity is merely one factor out of many in the analysis of rooftop solar versus utility-scale solar, and studies have shown that when all factors are considered, including the higher capacity factor of utility scale solar and the possible transmission loss reductions associated with distributed PV, utility-scale solar remains a far more cost-effective option for customers. (*Id.*) Perhaps most importantly, however, as UNS Electric witness Carmine Tilghman explained, TASC and Vote Solar ignore that DG systems are not placed strategically throughout the Company's territory but are installed randomly. (Exhibit UNSE-26 (Tilghman Rebuttal) at 14.) This not only minimizes any intermittency benefits offered by rooftop solar systems, but creates stability and integration issues that necessitate additional measures and improvements and thus additional fixed costs for the Company. (*Id.*)

TASC's claims that DG solar has lower "habitat, visual, and cultural" impacts than utility-scale solar are similarly unfounded. (*See* Exhibit APS-1 (Brown Surrebuttal) at 38-39.) As APS witness Brown testified, TASC witness Fulmer was opportunistically selective with respect to the items he chose to consider in the Department of Energy study he relied upon in making this argument, ignoring other negative externalities that the study associated with rooftop solar, including limiting or destroying trees and tree growth and the associated loss of aesthetic, shade, and carbon offset benefits, and reported conflicts over the visual impacts of rooftop solar, including issues with glare impacting neighboring homes and businesses. (*Id.*)

Moreover, while Vote Solar witness Kobor mentions in passing that a cost study might be useful (Exhibit Vote Solar-6 (Kobor Direct)), none of the "benefits" of rooftop solar that they have identified are of the type that could properly be included in a regulated cost-of-service study in any event. (*See* Exhibit AIC-D (Hansen

Surrebuttal) at 23.) Attributing the value of things like "environmental services" to solar DG and not to other activities that also confer the same benefit distorts customer incentives and leads to cross-subsidies—exactly what UNS Electric is trying to remedy with its proposals. (*Id.*)

More importantly, TASC and Vote Solar do not propose setting the Renewable Credit Rate at the precise value of DG solar. Instead, they recommend a continuance of the status quo. (*See* Exhibit TASC-21 (Fulmer Surrebuttal) at 30) (conceding that TASC and Vote Solar "simply opposed *all* rate design changes without proposing any substantive alternatives," because "TASC believes that net metering" should continue (emphasis added).). Yet TASC and Vote Solar have "*at no time . . . ever attempt[ed] to provide a justification why ratepayers should pay twice the amount for solar than what the Company can procure for an equivalent amount of solar on its distribution system.*" (Exhibit UNSE-27 (Tilghman Rejoinder) at 4 (emphasis in original).)

3. Modifying the Net Metering Rule Will Not Prevent UNS from Meeting its Renewable Energy Standard Requirements.

Intervenor Vote Solar's witness Briana Kobor also posits that a change to the net metering rate might result in UNS Electric failing to meets its distributed generation requirement in future years. (*See* Vote Solar-6 (Kobor Direct) at 52). However, Ms. Kobor fails to provide a shred of substantive evidence to support her allegations. Further, she implicitly concedes that there *is no* substantive evidence for this claim when, in the same breath, she criticizes the Company for "not analyz[ing]" the potential impact of these changes on rooftop solar installation rates. (*See id.*)

A more fundamental problem with Vote Solar's bald contention, aside from the total dearth of evidence to support it, is its irrelevance to this rate case. Renewable Energy Standards ("RES") are not an appropriate factor for the Commission to weigh in formulating rate design because the State-imposed renewable energy standards are entirely removed from rate design considerations of economic efficiency, equity, revenue adequacy and stability, bill stability and customer satisfaction. (*See* Exhibit APS-1 (Brown Surrebuttal) at 33; Exhibit APS-3 (Faruqui Direct) at 5-6.) If the Company needs additional DG solar to meet its RES requirements, they can seek cash incentives or other transparent subsidies during their RES Implementation Plan proceedings in order to achieve their RES requirement. (*See, e.g.,* Tilghman Hearing Testimony, Tr. at 1352:12-22.) Providing any necessary subsidy in a transparent fashion during the course of the Company's RES proceeding would allow the Commission and non-solar customers to better appreciate the magnitude of the solar subsidy that the DG carve out requires, far better than when the subsidy is embedded in utility rate design as it is today. (*See id.*)

4. Modifying the Net Metering Rule Will Not "Kill the Solar Industry."

Like they do with respect to demand charges, some intervenors proclaim that the proposed changes to the net metering tariffs will harm the solar industry. (*See, e.g.*, Exhibit Vote Solar-6 (Kobor Direct) at 5.) However, the testimony in this case shows that modernizing net metering tariffs is vital to the long-term stability of the solar industry and the renewable energy markets as a whole.

The current rate structure and net metering tariffs enable solar DG lessors and vendors to retain most of the margin in a DG solar transaction, passing pennies on the dollar in "utility bill savings" to solar DG customers while recovering the balance of their profits from taxpayer-funded subsidies plus cross-subsidies paid by non-solar customers. (Exhibit APS-1 (Brown Surrebuttal) at 14.) APS witness Cory Welch provided detailed testimony regarding the large surplus margins built into current rooftop solar pricing, which shows that rooftop solar lessors obtain, *on average*, 40% margins on each installation in UNS Electric's territory. (Exhibit APS-5 (Welch Surrebuttal) at Attachment CJW- 2SR.). Consequently, it is unsurprising that rooftop solar companies and associated interest groups, such as TASC and Vote Solar, oppose pricing reforms, because their business models are built on being shielded from competition. SolarCity essentially admits as much in its 10k filing, stating that:

> **Modifications to the utilities' peak hour pricing policies or rate design, such as to flat rate, would require us to lower the price of our solar energy systems to compete with the price of electricity from the grid.**

(*See* Exhibit APS-1 (Brown Surrebuttal) at 14 (emphasis added); *see also* Exhibit AIC-I (SunRun Investor Presentation at 2, stating that "[t]he risks and uncertainties that could cause our results to differ materially and adversely from those expressed or implied by such forward-looking statements include . . . changes in the retail prices of traditional utility generated electricity; changes in policies and regulations including net metering and interconnection limits or caps; [and] the availability of rebates, tax credits and other incentives.").)

What the objecting intervenors fail to explain, however, is why market competition is a negative, particularly from the standpoint of consumers and the public interest. With increased exposure to market risk, solar DG lessors and vendors would be compelled to lower prices and improve their products, which only makes them more attractive to the public and able to compete against other renewable energy technologies going forward. (*See* Exhibit APS-1 (Brown Surrebuttal) at 15.) The profit margins that solar DG lessors and vendors are currently obtaining strongly suggest that these same installations could be provided at a lower cost and still be profitable for the company. (*Id.*) Indeed, as observed by APS witness Ashley Brown, "with the UNSE proposed reference price, both vendors and customers would be incentivized to improve both efficiency and productivity, as the saving would accrue to them, but would be earned, as opposed to being the gifts of a severely flawed pricing methodology." (*Id.*) Instead, what TASC members seek is to preserve a business model that deprives customers of the pricing benefits associated with competitive markets and cost-based regulation. (*Id.* at 16.) This is not in the interest of *any* ratepayers, including UNS Electric's customers in particular.

Recognizing that they are advocating for bloated profits for solar DG companies, Vote Solar and TASC attempt to shift the focus to other hypothetical impacts that could result from net metering, including a projected reduction in the number of solar jobs. (*See* Exhibit Vote Solar-6 (Kobor Direct) at 55; Exhibit TASC-21 (Fulmer Surrebuttal) at 10.) Once again, however, Vote Solar and TASC fail to provide any specific evidence or analysis to establish even the current number of solar jobs in UNS Electric's territory, much less the impact of the Company's proposal on these yet-unidentified jobs. Instead, Vote Solar and TASC rely on the same Solar Foundation National Solar Jobs Census that they relied upon in proceedings before the Nevada Public Utilities Commission. (*See* APS-1 (Brown Surrebuttal) at 17-18.) However, the Nevada PUC staff rejected that census because it did not provide a reasonable estimate of solar jobs in Nevada or the number of jobs that could be impacted by the proposed net metering changes in that case. (*Id.*) The same is true here—that census has nothing to do with the number of solar jobs in either Arizona generally or the UNS Electric's service territory specifically, and it does not address the impacts of the changes proposed here.

There is also a more fundamental problem with Vote Solar's and TASC's claims about job creation—they conflate the creation of solar jobs generally with the creation of solar jobs under the current net metering regime specifically. (*See* Exhibit APS-1 (Brown Surrebuttal) at 18.) These intervenors do not even bother to claim that net metering creates more jobs than competitively priced solar would create. (*Id.*) Instead, they look at solar job creation in a vacuum and entirely fail to consider the broader effect on the economy. This is problematic for a couple of reasons. First, it ignores that most solar panels sold and leased in the U.S. are manufactured in China, which means that in all likelihood more American jobs are associated with other forms of generation. (*See* Exhibit APS-1 (Brown Surrebuttal) at 19.) Second, and more importantly, if the cost of electricity is higher, jobs are likely being lost elsewhere in the economy. (*Id.* at 18-19.) Indeed, a recent Arizona-specific regional economic study concluded that while there may be an immediate positive impact on some jobs from additional solar employment, over time, the impact on jobs and the gross state product of the Arizona economy are *negative* once the lost spending power by consumers who have to pay more for electricity is taken into account. (*See* Exhibit APS-1 (Brown Surrebuttal) at 18-19) (citing a study by Tim James, Anthony Evans, and Lora Mwaniki-Lyman of ASU). Once again, we see Vote Solar and TASC advocating for a short-term benefit to rooftop solar companies to the long-term detriment of ratepayers and the public interest.

At bottom, what is critical to understand is that net metering, regardless of its profitability for solar DG companies, is so poorly designed that it cannot be sustained in the long term and thus runs contrary to the economic viability of distributed solar energy. (*See* Exhibit AIC-1 (Brown Surrebuttal) at 31.) Vote Solar and TASC point to the net metering changes made by the Nevada PUC as evidence of the dire consequences for the solar industry that might result from UNS Electric's proposals here. (Exhibit TASC-21 (Fulmer Surrebuttal) at 28-29; Exhibit Vote Solar-7 (Kobor Surrebuttal) at 9.) But the Nevada PUC decision merely reinforces that it is better to make these changes *now*, before more consumers buy into a broken system, because no one can deny that these changes, or ones like them, will have to happen eventually. "In fairness to both DG and non-DG customers alike, it is important to get rate signals correct and sustainable ***as soon as possible***." (Exhibit APS-1 (Brown Surrebuttal) at 31.)

C. Buy-Through Rate

"I see no reason to rush into it, especially with a company that appears unwilling to support the buy-through."

- Testimony of Howard Solganick on behalf of Commission Staff (Solganik Hearing Testimony, Tr. at 2745:21-23).

1. The Commission Should Wait to Assess the Data Presented in Arizona Public Service Company's Pilot Buy-Through Rate

Program Before Implementing a Buy-Through Rate for other Arizona Utilities.

AIC strongly opposes the implementation of a buy-through rate for UNS Electric Company, Rate Rider 14, which UNS Electric was required to propose as the result of a preceding settlement agreement but actively opposes, rightly noting that "[i]t allows for certain large companies to 'cherry pick' currently available capacity resulting from current economic conditions and will ultimately result in costs being passed on to the remaining customers." (Exhibit UNSE-31 (Jones Direct) at 56.)

The concept of a buy-through rate originated in APS's last rate case, in which the buy-through rate proponents in this case (specifically AECC, Noble Solutions, Freeport McMoran, and Wal-Mart), were parties. (Higgins Hearing Testimony, Tr. 1120: 4-14; McElrath Hearing Testimony, Tr. 1187:19 – 1188:11; Hendrix Hearing Testimony, Tr. at 1205:16 -1206:13.) Each of these parties agrees (1) that the APS buy-through rate was intended to be experimental in nature; (2) that the results of the APS buy-through program will be presented and analyzed during APS's next rate case, to be filed in June of this year; and (3) that the Commission will decide whether and how to modify APS's buy-through rate in the course of that rate proceeding. (*Id.*) These parties have also indicated that they intend to participate in APS's upcoming rate case filing and will participate in the discussions regarding the APS AG-1 program at that time. (*Id*).

Neither do the buy-through rate proponents dispute that evidence exists demonstrating that the APS experimental buy-through program has serious flaws. In response to a data request from AIC, APS estimated that "the net losses from the AG-1 [buy through] program from the program start in November 2012 to May of 2015 were approximately $16.8 million"—a number that would have been $45.3 million had APS not retained the ability to mitigate program losses by keeping a portion of off-system sales margins rather than passing those margins to customers through APS's fuel adjustment clause. (*See* Exhibit AIC-B (Yaquinto Surrebuttal) at 4-10.)

APS further explained that the management fee and capacity reserve charge included in its buy-through program were insufficient, and that the "woefully inadequate" management fee "should at least be doubled." (*Id.* at Exhibit C.) Both AECC/Noble Solutions witness Higgins and Freeport McMoran witness McElrath concede that they have no reason to dispute APS's representations in this regard. (*See* Higgins Hearing Testimony, Tr. at 1154:4-8; McElrath Hearing Testimony, Tr. at 1189: 2-4.) To the contrary, Mr. McElrath expressly stated with respect to the APS data that he "would expect it is very accurate." (McElrath Hearing Testimony, Tr. at 1189: 2-4.)

Notwithstanding this concerning and "very accurate" program data that will be presented for Commission review and analysis in the course of a few weeks, the buy-through rate proponents seek in this case to implement a similar program for UNS Electric that they would model after the APS AG-1 rate. In fact, AECC/Noble Solutions witness Higgins would have the UNS Electric program be "as similar as reasonably possible" to the APS buy-through proposal, but for the program's funding mechanism. (Higgins Hearing Testimony, Tr. at 116:21-25.) Mr. Higgins recommends this outcome notwithstanding his agreement that the APS buy-through rate management fee may be too low even for APS and that the management fee for UNS Electric might reasonably be even higher given that APS is a bigger company than UNS Electric and thus has economies of scale that UNS Electric lacks. (Higgins Hearing Testimony, Tr. at 1126-27.) In addition to the parties' disagreement over the appropriate management fee, they also dispute the correct sizing of the capacity reserve charge. (Jones Hearing Testimony, Tr. at 2008:24 – 2009:5.) And while Wal-Mart witness Hendrix recommends that the buy-through rate program charges be based on costs, he acknowledges that these costs are not currently known. (Hendrix Hearing Testimony, Tr. at 1212:1-3.)

The lack of certainty regarding these and other facets of a buy-through rate program underscores that it is simply premature to implement such a program in the UNS Electric service territory at this time. The Commission will evaluate the APS program data in short order and can choose to either modify its design to correct for the alleged deficiencies or perhaps even discontinue it as contrary to the public interest. (Jones Hearing Testimony, Tr. at 2009: 21-25.) Until these issues are thoroughly resolved and the right program designed based on the APS data that is four years in the making, it makes little sense to move forward with another buy-through experimental program for another utility—particularly one as small as UNS Electric, which is already experiencing revenue losses resulting from the departure of some of its larger customers from its system. (*See* Exhibit AIC-B (Yaquinto Surrebuttal) at 4-10.)

2. The Opportunity for Choice Comes at a Cost with AECC's Proposed Funding Mechanism.

Although AECC witness Kevin Higgins has proposed a funding mechanism that he asserts would resolve the potential for financial harm to UNS Electric or its customers, no party to this case but those who stand to profit from the buy-through rate are comfortable that such a funding mechanism alleviates the concerns about it. As AIC understands Mr. Higgins' proposal, he would reserve $908,000 of the revenue requirement reduction that would apply to customers in the classes that are eligible for Rate Rider 14 and use that amount to fund the buy-through program. (Higgins Hearing Testimony, Tr. at 1138:1 – 1140:15). Put another way, Mr. Higgins would raise the rates that would otherwise apply to customers eligible for the program in order to allow a select few of them to participate in it. (Jones Hearing Testimony, Tr. at 2671:5-15.)

And while Freeport McMoran witness McElrath suggested that the opportunity to participate in the buy-through program was worth the cost, UNS Electric's largest customer, Nucor, disagrees. As Nucor witness Dr. Zarnikau testified, Nucor has not determined whether it would want to participate in a buy-through program and would not want other participants to "dump costs on Nucor." (Zarnikau Hearing Testimony, Tr. at 2446:20 – 2447:5). Freeport, for its part, has no load in the UNS Electric service territory and has no current plan to expand into that territory. (McElrath Hearing Testimony, Tr. at 1184:24 – 1185:22).

Moreover, the evidence was far from clear that Mr. Higgins' proposed funding mechanism would insulate UNS Electric from monetary harm in any event. UNS Electric witness Jones testified that he did not believe that the funding mechanism would adequately protect the Company. (Jones Hearing Testimony, Tr. at 2008:17-23.) Commission Staff also made clear that they oppose a buy-through rate if it would have an adverse impact or a cost to other non-participating customers (*See* Exhibit S-5 (Solganick Rate Design Direct) at 48), and was not convinced that Mr. Higgins' proposal addressed Staff's concern. As Staff witness Solganick explained:

> If a customer wins the lottery and makes savings greater than their share of $908 [thousand], they are okay. But if a company, for either fear of the marketplace or lack of technical expertise or just dumb luck or bad luck in a lottery loses, then they get to pay the share of $908,000 while one of their neighbors gets reduced rates.

(Solganick Hearing Testimony, Tr. at 2741:8-15). Staff was therefore "not convinced that the solution protects everybody." (*Id.*) Mr. Solganick also explained that the very nature of a buy-through program has the potential to raise rates for non-buy-through customers in the long run, and expressed his concern that "buy-through doesn't have a long-term component that hits the company at the worst possible time and, since it's a pass-through, hits all of the customers at that time." (Solganick Hearing Testimony, Tr. at 2743:3-6).

UNS Electric's large customers have other options to achieve power cost savings without imposing costs on other customers, including the ability to execute a special contract with the utility or install customer-sited generation. (Higgins Hearing Testimony, Tr. at 1167: 19-21; McElrath Hearing Testimony, Tr. at 1186: 1-13). And postponing any decision on the buy-through rate in this case does not signal the Commission's intent never to implement the program, if the Commission decides that a buy-through rate is in the public interest and develops the right program design using the APS data. In the end, it is better to get it right than right now.

D. Economic Development Rate

AIC also supports UNS Electric's proposed Rate Rider 13, the proposed Economic Development Rate. UNS Electric's service territories have been slower to recover from the economic recession that other parts of Arizona (*See* Exhibit UNSE-28 (Dukes Direct) at 31), and encouraging economic development through incentives like discounted electricity rates will facilitate that recovery—to the benefit of the Company and all of its customers. (*See* Exhibit AIC-A (Yaquinto Direct) at 8-9.) Attracting new businesses to locate or expand in rural Arizona is difficult, and Rate Rider 13 will allow these smaller communities the opportunity to compete for customers with other areas in Arizona and other states that have location amenities and advantages that Mohave and Santa Cruz counties may lack.

UNS Electric also has sufficient capacity to accommodate these discounts for attracting new business. (*See id.* at 9.) Further, the program targets those customers that UNS Electric can most efficiently serve through its facilities—i.e., new or expanding operations with high peak load demand and load factor characteristics—thereby alleviating any potential concerns over cost-shifts. (*Id.*) Finally, because UNS Electric is piggybacking onto the State's economic development tax credits for eligibility requirements, the Company mitigates administrative costs related to implementing this tariff and concerns over "free ridership." (*Id.*) For all of these reasons, AIC strongly supports the Company's proposed Rider 13 to implement an Economic Development Rate.

II. CONCLUSION

For the foregoing reasons, AIC urges the administrative law judge to recommend that the Company's residential rate design, net metering, and economic development rate proposals be granted, and the buy-through rate be rejected.

RESPECTFULLY SUBMITTED this 25th day of April, 2016.

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