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AZ CORP COMMISSION
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**ORIGINAL**

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR APPROVAL OF NET METERING COST SHIFT SOLUTION.

Arizona Corporation Commission
DOCKETED
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DOCKETED BY

DOCKET NO. E-01345A-13-0248

**TUCSON ELECTRIC POWER COMPANY AND UNS ELECTRIC, INC.'S COMMENTS TO STAFF REPORT AND PROPOSED ORDER**

Tucson Electric Power Company ("TEP") and UNS Electric, Inc. ("UNS Electric") (collectively, the "Companies"), through undersigned counsel, hereby file comments on the Arizona Corporation Commission (the "Commission") Utilities Division ("Staff") report and proposed order filed in this docket on September 30, 2013 ("Staff Report"). These comments also respond to the questions posed by Commissioner Pierce in his October 17, 2013 letter that was filed in the docket. The Companies agree with Arizona Public Service ("APS") that Arizona's net metering rules have created serious problems that need to be addressed promptly. The Companies' customers are facing the same inequitable cost shifting issues as more distributed generation ("DG") is being deployed in their service areas.

The Companies are encouraged by the Staff's acknowledgement that inappropriate cost shifting is occurring under the net metering rules. Moreover, the Companies agree with the Staff's proposal to issue a Consumer Protection Advisory to further educate and protect customers. However, the options set forth in the Staff Report are not in the public interest, as they do not sufficiently mitigate the inequitable cost shifting that the net metering rules impose on the vast majority of customers who lack net-metered DG systems.

The two solutions proposed by APS in its application would effectively mitigate the inequitable cost shifting, thereby ensuring that all customers connected to the electric grid contribute appropriately to support its maintenance and operations.[1]

The Residential Utility Consumer Office ("RUCO") also has offered a phased-in, market-based charge for DG users that could mitigate cost shifting effectively, provided that the charge is higher than RUCO recommends. RUCO's proposed charge reflects a flawed, overly optimistic appraisal of the value that DG solar power systems might someday provide to utilities and other customers. However, with a more appropriate valuation of known and measurable costs and benefits, RUCO's method could offer a simple, flexible way to mitigate the impact of DG cost shifting.

The Companies urge the Commission to act promptly to avoid additional cost shifting from new DG installations under the current net metering rules and to provide guidance to utilities, the solar industry and consumers as to the appropriate level of net metering compensation.

## A. Background.

The net metering rules (A.A.C. R14-2-2301 *et seq.*) were adopted in 2009 to facilitate and incent the deployment of certain DG resources. In combination with incentives offered under the Renewable Energy Standard Tariff ("REST"), the net metering rules "jump-started" DG adoption rates for otherwise costly photovoltaic ("PV") systems. In recent years, though, falling PV prices and the growing availability of leased systems have significantly boosted DG adoption rates, allowing the Commission to scale back incentives without compromising Arizona's ranking as a solar energy leader.

The rapidly expanding deployment of net-metered solar DG is undermining electric utilities' ability to recover the cost of deploying, maintaining and operating the electric grid.

[1] For purposes of the discussion herein, "grid" is defined to include distribution and transmission facilities, voltage support, other ancillary and balancing services, must-run generation and generation capacity.

Much of the challenge results from rates that are designed to recover the majority of utilities' fixed service costs from usage-based kilowatt-hour ("kWh") charges. While DG systems do not reduce utilities' fixed costs, they do reduce the usage-based revenues intended to cover those expenses.

The current net metering rules exacerbate the problem. The rules over-compensate net-metered customers by effectively excusing them from paying their share of fixed costs related to the operation and maintenance of the grid that serves them. Every net-metered customer is connected to the grid maintained and operated by the utilities. Net-metered DG users depend on the grid every bit as much as other customers, imposing comparable costs and peak energy demands. They rely on the utility system every second of even the sunniest of days to stabilize and supplement the intermittent, and often inadequate, output of their DG systems. Yet, under the net metering rules, net-metered customers avoid paying any significant portion of the fixed costs of the grid necessary to serve them. Those avoided fixed costs are ultimately passed on to other customers, resulting in a significant subsidy to net-metered customers.

In this way, the current net metering rules provide DG users with a significant subsidy that shifts costs to other utility customers. Although this subsidy might have served the Commission's initial policy objective of creating a more robust DG market in Arizona at an early stage of development, the time has come for the Commission to address the inequitable long-term impacts of the current net metering rules as DG deployment continues to expand. Without prompt resolution, this problem will only grow, making future solutions more difficult to implement.

**B. Net Metering has Created an Acknowledged Problem that Will Only Get Worse.**

APS' application in this docket clearly and appropriately presented the net metering problem that faces all Commission-regulated electric utilities across Arizona. In its Staff Report, Staff has acknowledged that the current net metering rules shift costs to other customers:

> *With increasing levels of DG penetration, the potential of shifting costs from customers with DG systems to those customers without such systems becomes apparent.* (Staff Report at 4)

Staff also has recognized this cost shifting issue has become a concern in other states that have experienced relatively rapid DG growth. (Staff Report at 9) In California, for example, the costs shifted to other utility customers by that state's current net metering rules are projected to exceed $1 billion by 2020, according to the California Net Metering Draft Cost-Effectiveness Evaluation docketed by Commissioner Pierce on September 30, 2013.

RUCO also recognizes the impact of DG cost shifting on other utility customers and recommends that the Commission take action now before its impact grows more significant:

> *If one ignores a fast moving trend that enables customers to avoid paying their appropriate share of fixed costs then these remaining fixed costs reallocated to non-adopters would be* [sic] *eventually become too great.* (RUCO Comments at 3)

The growing prevalence of DG creates new policy challenges that require new regulatory approaches. These issues are beginning to be addressed by regulators and stakeholders. The Critical Consumer Issues Forum ("CCIF"), which engages state public utility commissioners, consumer advocates and electric companies to develop mutually agreeable solutions to energy challenges, recently released a report on policy considerations related to DG resources. The report set forth numerous principles to help guide regulators in setting appropriate policies for DG issues. These principles include:

- Generally, DG costs imposed on utilities should be borne by those that cause the costs. For example, backup or standby utility costs (particularly regarding intermittent DG technologies) should be borne by the DG system operator.

- Any required allocation of costs to others should be rational, transparent, based on benefits received, and not unduly burdensome.

- DG incentives should be based on clear policy objectives and periodically reevaluated based on market conditions. Once the underlying policy objectives are met or as the technologies become cost-competitive or cost-prohibitive, such incentives should be modified or discontinued.

- In developing DG policies, particular attention should be given to the cost impacts on all utility customers, including those not participating and those least able to afford such costs.

The CCIF's report summary is available at http://www.criticalconsumerissuesforum.com/wp-content/uploads/2011/09/CCIF-DER-Principles-Final-June2013.pdf and is also attached to these comments as Attachment A.

## C. Prompt Intervention is Critical to Avoid Bigger Problems in the Future.

DG is being deployed in Arizona at a rapid pace. Falling PV prices and the increased availability of leased systems – which have been made more affordable by significant tax incentives – have continued to drive the proliferation of solar in Arizona, even as the Commission has reduced up-front incentives to practically zero.

Almost every day, new net-metered DG systems are being connected to a utility grid. All these newly net metered customers will rely on the grid night and day to stabilize and supplement their systems' output, particularly during peak periods and during the summer months. Yet under the current net metering rules, all of these customers will avoid paying the fixed costs of the grid necessary to serve those needs.

If the Commission delays addressing the shortcomings of the current net metering rules, the magnitude of the cost-shifting will increase and the problem will be much more difficult to resolve in a fair and equitable manner.

## D. Staff's Proposals are Inadequate to Address the Growing Net Metering Problem.

Staff acknowledges the inequitable cost shifting and appears to recognize that the Commission must address it. However, the options proposed by Staff are simply inadequate. Staff's options either delay resolution of the problem or take a piecemeal approach that fails to effectively mitigate the cross subsidization.

Staff's first recommendation – that the Commission delay addressing the issue until APS's next rate case – only exacerbates the cost-shifting problem. APS is precluded from filing another rate case until May 31, 2015, and new rates for APS cannot go into effect until July 1, 2016. Given APS' estimate of approximately $6-10 million of additional cost shifting annually, Staff's first option would allow $20-25 million of additional cost shifting to customers in APS' service territory. That amount does not include the increasing cost shifting in TEP's and UNS Electric's service areas, or comparable costs in the service areas of the electric cooperatives. Given these escalating impacts, it would be irresponsible for the Commission to stand by and do nothing while an acknowledged problem imposes ever-increasing costs on a majority of utility customers.

Meanwhile, the two alternatives Staff proposes as "bridge solutions" don't extend nearly far enough to address the problems raised by current net metering rules.

**Staff Recommended Alternative #1.**

This option would apply APS' existing fixed Lost Fixed Cost Recovery ("LFCR") charge option – currently $2.76 per month – to all net-metered customers. This amount is simply too small to materially impact the inequitable cost shifting. APS has stated in this docket that its net-metered residential DG customers are shifting, on average, $800-$1000 in unpaid service costs to other customers on an annual basis. The proposal to mitigate just $33.12 of this significant annual cost shift is simply inadequate even as an interim step.

**Staff Recommended Alternative #2.**

Staff's second proposal would charge net metered customers a higher fixed LFCR charge based on the price APS would pay for utility-scale solar energy through a hypothetical power purchase agreement ("PPA"). Establishing that price would require a complex, subjective process that would give rise to significant dispute. Moreover, the resulting charge would not reflect the true cost of net metering: the amount of fixed service costs shifted to other customers.

The practical challenges imposed by Staff Recommended Alternative #2 will likely become apparent upon review of the figures provided by various parties in response to an Oct. 17, 2013 letter from Commissioner Pierce. The letter asks parties to provide "realistic" rates and other appropriate inputs for the calculation proposed by Staff, assuming that "utility scale" refers to a 1-5 MW system interconnected at the sub-transmission level. Although the Companies cannot know in advance what figures others will file, it seems likely that parties in this hotly contested docket will have dramatically different ideas about what values are "realistic."

In response to Commissioner Pierce's request, the Companies offer the following figures, which reflect actual data from TEP's and UNS Electric's renewable energy programs:

**TEP**:

| | |
|---|---|
| A. Avg. Residential Customer DG size | 6.8 kW |
| B. Assumed Annual Rate of Production | 1,850 kWh/kW |
| C. Calculated Annual Production | 12,580 kWh (A x B) |
| D. Assumed Customer retail rate | $0.11/kWh |
| E. Annual Retail Cost of Production | $1,383.80 (C x D) |
| F. Assumed Utility Scale PA rate | $0.082/kWh |
| G. Annual PPA cost of production | $1031.56 (C x F) |
| H. Annual DG premium | $352.24 (E – G) |
| I. Monthly DG Premium | $29.35 (H/12) |
| J. LFCR DG Premium per kW | $4.32 (I/A) |

**UNS Electric**:

| | |
|---|---|
| A. Avg. Customer DG size | 8.1 kW |
| B. Assumed Annual Rate of Production | 1,750 kWh/kW |
| C. Calculated Annual Production | 14,175 kWh (A x B) |
| D. Assumed Customer retail rate | $0.11/kWh |
| E. Annual Retail Cost of Production | $1,559.25 (C x D) |
| F. Assumed Utility Scale PA rate | $0.082/kWh |
| G. Annual PPA cost of production | $1162.35 (C x F) |

| | | |
|---|---|---|
| H. | Annual DG premium | $396.90 (E – G) |
| I. | Monthly DG Premium | $33.08 (H/12) |
| J. | LFCR DG Premium per kW | $4.08 (I/A) |

These figures reflect the typical size and performance of DG PV systems installed in the service territories of TEP and UNS Electric, as well as the costs paid by both companies in recent PPAs. As such, they are preferable to hypothetical values that might be generated through requests for proposals ("RFPs"), projections or industry valuations based on sales and systems elsewhere. Yet, if the Commission were to adopt Staff Recommended Alternative #2, even figures based on the real-world experience of regulated utilities would be subject to vigorous debate. Stakeholders might, for example, seek to limit or expand the number and type of contracts incorporated in the calculated average to move the "Assumed Utility Scale PPA Rate" higher or lower. Alternatively, stakeholders could dispute the "Assumed Annual Rate of Production," seeking to drive it higher or lower – by excluding or including systems installed during certain time periods, for example – to influence the calculation of the "Annual DG Premium." Because these premiums would need to be reset annually to reflect changing market conditions, such contentious debates would come before the Commission each and every year.

If the Commission prefers to mitigate cost-shifting through the price paid for excess DG output, that rate should reflect a transparent, independent market-based value rather than the contentious and subjective process proposed in Staff Recommended Alternative #2. A more direct approach, though, would seek to recover the actual costs shifted from DG users to other customers under current net metering rules. Developing an LFCR charge for net metered customers that fairly reflects the actual costs they avoid would be more reliable, straightforward and equitable than the approaches recommended by Staff.

### E. APS' Proposals.

Of the two proposals offered by APS, the Companies prefer the proposed demand charge tariff as an appropriate way to mitigate cost shifting from net-metered DG customers.[2] While APS's proposal for adjusting the net metering offset or credit from the retail rate to a wholesale rate also would reduce cost shifting, the Companies recognize that this approach might raise additional legal or tax concerns for both utilities and customers.

### F. RUCO's Proposed Alternative.

In its October 30, 2013 Comments, RUCO proposes that net-metered DG system users should pay a fixed LFCR charge based on their system's capacity (in kilowatts, or "kW"). The charge would reflect both the fixed system costs shifted to other customers and the economic benefits created by DG systems, and it would be phased in over time until "rooftop solar is cost neutral to non-solar residential ratepayers over 20 years." (RUCO Comments at 2) Such a charge would be revenue-neutral for utilities and, if set at the appropriate level, could relieve customers of the undue impact of cost-shifting from net-metered DG customers.

Although RUCO's conceptual approach has merit, RUCO errs in proposing a negligible \$1/kW fee that would increase over time to just \$3/kW, or about \$20 for a typical residential DG user. The amounts reflect RUCO's inappropriate decision to offset the established, proven costs that net-metered customers are shifting to other customers today with unsupported and overly optimistic estimates of future savings that utilities and, by extension, other customers might theoretically realize through the long-term use of DG systems. RUCO's speculation does not reflect the reality that slower load growth has scaled back past assumptions about the need for future generation and transmission additions. *In fact, the only new fossil-fueled generation additions anticipated by TEP's most recent 20-year Integrated Resource Plan ("IRP") are gas-fired turbines that will be needed to balance and back up the intermittent output of DG systems and other renewable energy resources.* The cost of those turbines and other DG integration

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[2] Neither of the Companies currently have a residential tariff that includes a demand charge. However, both Companies have the ability to address this prior to their next rate cases.

expenses are not reflected in RUCO's calculation. Indeed, in its bid to provide DG users with the full advance benefit of 20 years of highly speculative future savings, RUCO entirely neglects future utility costs – including all of the new expenses utilities will incur over the next two decades to maintain safe, reliable operation of the electric grid for all customers.

The speculative savings incorporated in RUCO's calculations are neither *known nor measurable*, and thus cannot be used as the basis for cost-of-service rates or surcharges. Just as utilities cannot seek advance recovery of construction costs for power plant additions referenced in their IRPs, they cannot be expected to credit customers today for costs that may (or may not) be avoided a decade from now. In this docket, the Commission should seek to mitigate the known and measurable costs being shifted by DG users to other customers. If the savings anticipated by RUCO materialize, they can then be incorporated in future calculations at the appropriate known and measurable levels.

If RUCO's proposal is modified to incorporate a more accurate and appropriate calculation of current costs and benefits, the agency's recommended mechanism – a fixed LFCR fee for DG users that reflects their system's generating capacity – could effectively mitigate the acknowledged cost shifting problem.

## G. Conclusion.

On behalf of the vast majority of our customers, the Companies join APS in asking the Commission to address the cost shifting resulting from net metering *now*. Delaying the resolution of the issue will only exacerbate the inequity arising from current rules and would not serve the public interest. APS has presented two appropriate solutions to this dilemma, while RUCO has proposed another method that, with reasonable modifications, could effectively mitigate cost shifting from DG users to other customers.

The Companies appreciate Staff's recognition of the cost shifting problem, but Staff's proposed solutions do not sufficiently address that problem. Therefore, the Companies request that the Commission approve APS' request in this docket or a revised version of RUCO's proposal that more accurately reflects the true cost-shifting impact of the current net metering rules.

Respectfully submitted this 4th day of November 2013.

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# ATTACHMENT

# "A"

# CCIF
Critical Consumer Issues Forum

# Policy Considerations Related to *Distributed Energy Resources*



## Introduction to CCIF Initiative on Distributed Energy Resources (DER)

*What is DER?* Distributed Energy Resources (DER) include distributed generation, which are non-centralized sources of electricity generation generally interconnected to the distribution system and located at or near customers' homes or businesses. While DER can include energy efficiency and demand response, this collaborative process focuses on distributed generation. Examples of DER addressed by this collaborative include solar panels, energy storage devices, fuel cells, microturbines, reciprocating engines, small wind, backup generation, CHP systems, etc.

*What is CCIF's Objective?* The role of DER is growing and may require new approaches for providing and regulating electricity services. We recognize the need for a better understanding of costs and benefits of DER. Our goal is to develop a framework to assist policymakers and other stakeholders in evaluating issues related to the potentials and challenges of DER in providing safe, reliable, affordable, cost-effective, and environmentally sound energy supply. In developing this framework, we recognize the differing regulatory and market structures (e.g., vertically integrated, wires-only utilities, etc.) of the states, as well as the potential significance of regional and federal requirements.

## Potential Benefits & Challenges of DER

When paired with appropriate public policies, DER has the potential to provide direct and indirect **benefits** to consumers, both individually and collectively. Depending on the type of DER, benefits that may be realized include:

1. Cost and risk reduction benefits;
2. Security and reliability;
3. Environmental benefits;
4. Innovation, expanded research and development, and other economic benefits; and
5. Expanded customer choice and control.

Likewise, the **challenges** associated with DER should be considered. Depending on type of DER, such challenges may include:

1. Financial impacts on utilities and customers, including increased costs, revenue losses, and cost-shifting;
2. Safety, security, operational control, reliability, and planning;
3. Siting, permitting, and other environmental issues;
4. Maintaining consumer protection standards; and
5. Jurisdictional and regulatory issues.

## Principles on Distributed Energy Resources

### *Financial & Regulatory Issues*

1. Generally, DER costs imposed on utilities should be borne by those who cause the costs. For example, backup or standby utility costs (particularly regarding intermittent DER technologies) should be borne by the operator of the DER.
2. Any required allocation of costs to others should be rational, transparent, based on benefits received, and not unduly burdensome.
3. DER incentives[1] should be based on clear policy objectives and periodically reevaluated based on market conditions. Once the underlying policy objectives are met or as the technologies become cost-competitive or cost-prohibitive, such incentives should be modified or discontinued.
4. Any incentives, through ratemaking practices, taxes, or otherwise, should be fair, transparent, and appropriate.
5. Utility investments required to accomplish DER deployment should be consistent with state policies and recovered in a manner consistent with state laws and regulatory policies.

[1] For purposes of this discussion, participants considered "incentives" as benefits received by or cost reductions to a DER project, such as tax subsidies, rebates, subsidized financing, any net metering arrangement that provides benefits exceeding the underlying value of the energy received from that DER, etc.

6. To the extent that state commissions evaluate new regulatory policies and procedures in light of increased emphasis on DER, they should take into account the interests and concerns of all stakeholders.

*Market Development & Deployment Issues*

7. Utility and regulatory processes and requirements should allow for customer deployment of DER technologies subject to reasonable rules and regulations.
8. Utility participation in DER markets should be fair, reasonable, non-discriminatory, and overseen and approved by the appropriate regulatory authority.
9. Policies related to DER interconnection or deployment should be fair, reasonable, not unduly discriminatory, and overseen and approved by the appropriate regulatory authorities.
10. DER should be permitted on either the customer side or the utility side of the meter in accordance with interconnection rules and other applicable regulations.
11. While policies and their application may vary by state, DER programs, grants, or subsidies should be periodically evaluated for cost-effectiveness and adjusted by the appropriate regulatory authority as market conditions and policy objectives or requirements change.
12. Utilities and DER providers should work toward appropriate and reasonable data sharing that facilitates capturing system benefits and identifying costs of DER.

*Consumer Issues*

13. As DER technologies are deployed, consumer protection policies should be periodically reviewed and revised as appropriate. In any event, consumers should be given a clear avenue to resolve complaints.
14. Utilities and DER providers, with the participation of state regulatory bodies and consumer advocates, should develop standards for data protection, access, and disclosure consistent with state requirements.
15. States, consumer advocates, and utilities should coordinate education and customer engagement programs and make available objective information associated with DER technologies.
16. In developing DER policies, particular attention should be given to the cost impacts on all utility customers, including those not participating and those least able to afford such costs.

*Safety, Reliability & System Planning Issues*

17. Utilities should be aware that changes to utility system planning and operations may be required because of greater integration of DER technologies.
18. DER interconnection standards, procedures, and practices must ensure the safety of the public, first responders, and electric utility workers. These standards, procedures, and practices must also protect utility and customer assets.
19. DER deployment must be accomplished in a manner that does not compromise the continued reliability of utility infrastructure and operating systems.
20. DER deployment should not diminish infrastructure security or cybersecurity.
21. Transmission and distribution planning entities should consider and incorporate as appropriate state DER requirements into their planning processes.