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BEFORE THE ARIZONA CORPORATION COMMISSION

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

Docket No. E-01345A-13-0248

RUCO'S NOTICE OF FILING COMMENTS

The Residential Utility Consumer Officer hereby provides notice of filing its Comments in response to Staff's Memorandum and Proposed Order of September 30, 2013 and Commissioner Pierce's letter to the docket of October 17, 2013.

RESPECTFULLY SUBMITTED this 30th day of October, 2013.

Daniel W. Pozefsky
Chief Counsel

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By Cheryl Fraulob
Cheryl Fraulob

TO: THE COMMISSION

FROM: Residential Utility Consumer Office

DATE: October 30, 2013

RE: RUCO's Comments in Response to Staff's Memorandum and Proposed Order of September 30, 2013 and Commissioner Pierce's Letter to the Docket of October 17, 2013.

The current net metering debate is a sub-component of a much larger debate about the implications and benefits of new technology, the value of the electric grid, and rate design. The Residential Utility Consumer Office (RUCO) agrees with Arizona Corporation Commission (ACC) Staff that this issue should be part of a broader discussion such as a rate case. However, RUCO recognizes the situation relating to Arizona Public Service's (APS) stay-out provision along with the Commission's desire to see this matter addressed now. RUCO did find a net cost shift occurring. Therefore, RUCO recommends that the ACC open up a docket to investigate the broader issues, while at the same time adopting the RUCO interim solution now and require APS to file a rate case no later than 2016.

For the interim solution, RUCO recommends a market based fixed charge on every new solar customer's bill to start addressing this immediate net metering issue. This fixed charge uses the same legal lost fixed cost recovery (LFCR) mechanism as Staff proposes in their alternative options. Once totaled, RUCO's proposed charge starts to address the distribution/delivery portion of the bill. In other words, rooftop solar customers need to pay for the grid they rely on throughout the day. Moreover, it levels the playing field between different solar technologies. RUCO arrives at the figures detailed below by recognizing a set of potential benefits and subtracting them from the cost shift that occurs with each deployed system. To expand more on rectifying the cost shift, below is a summary of RUCO's findings and policy recommendations:

- There is a value gap with rooftop solar on APS rates. This means that the benefits of roof top solar do not cover the cost shifts to non-solar ratepayers resulting in a near term cost shift and long-term cost shift of $20 per month or $3/kW.
- A higher LFCR charge on new solar customer bills should be implemented to address this value gap.
  - This higher charge does not increase the total revenues collected by APS. Instead, it simply reduces the LFCR charge for non-solar customers.
- The charge should start at $1/kW and increase over time.
  - Since there is uncertainty over the impact this charge will initially have on new installations (and the ability for additional residential ratepayers to go solar), RUCO strongly recommends a gradual phase-in tied to market

demand. RUCO believes that starting at a level beyond $1/kW could start to trigger rapid declines in installs and significantly hurt the industry.
    - Once the market can accommodate a $3/kW charge, rooftop solar is cost neutral to non-solar residential ratepayers over 20 years but there is still a near-term cost shift to mitigate.
- To provide regulatory certainty, the charge should be locked in for 20 years, and linked to the system not homeowner.
- The phase-in of the charge should be designed to mirror the existing approach Arizona utilities have taken toward upfront incentives, which have gradually declined over time in conjunction with market demand.
    - Every 20 MW triggers a $0.50/kW increase to the LFCR charge.
    - For example, a 7 kW system would start at $7 per month and then after the market reaches 20 MW, the charge for a new 7 kW system would go to $10.50 (a $3.50 increase).
- To avoid excess cost shifting any system 16 kW and above should be assessed at a $3/kW rate. That would translate to a $48 per month charge.
    - To ensure pricing is still current, periodically the utility should determine the capacity value of solar photovoltaics (PV) using the method they readily use today (subject to the Commissions oversight).
- The market driven mechanism should consider compliance requirements in the DE carve out.

The end result of this policy is a protection of residential non-solar ratepayers from excessive cost shifts and market certainty to the solar industry. In doing this, RUCO's proposal balances the positions of Staff, the solar industry, and APS.

Introduction:

Net metering and customer sited generation is a multi- faceted issue that draws complexities from many parts of rate-making. For instance, the topic of shifting costs to one segment of residential ratepayers to another. Cost shifts are pervasive throughout the regulatory model, some based on policy, and some the natural result of a regulatory framework that needs to be manageable and not overly complex. The Residential Utility Consumer Office (RUCO) feels that the cost shift issue brought up by Arizona Public Service (APS) deserves a larger conversation that is not specific to residential distributed generation (DG) solar. A rate case or separate docket would be most appropriate. RUCO's first recommendation is for the ACC to open a docket to explore the implication of new technology, not just rooftop solar. The Commission could then require APS file after the stay-out in 2016.

In addition to the rate case, RUCO recommends a market based fixed charge on new solar customer bills. RUCO's policy proposal is technology agnostic and determines the level of the charge based on outcomes that can benefit non-adopters to judge value. While this is in the context of residential photovoltaic (PV) solar, RUCO's policy solution can be a platform on which to evaluate other technologies, it can also be applied statewide. In other words, the policy can be used to ensure that Arizona is a smart adopter of new technology over a first adopter.

RUCO's guiding principles for designing a fair policy for DG:

In crafting the policy, RUCO developed five guiding policy principles:

1. Fair allocation of costs and benefits to solar and non-solar customers.
2. Sustainable statewide policy platform that prepares DG to flourish without long-term negative impacts to non-solar residential ratepayers.
3. Market-based encouragement of new technologies that does not pick winners or losers.
4. Measured approach to DG deployment based on what the utility system needs.
5. Incremental approach that is easy for customers to understand and facilitates financing.

Regulatory reforms are needed to support sustainable DG, but other stakeholders' proposals fall short:

The current regulatory model is not designed to properly measure the benefits and costs of customer sited generation. The model was built around central generation with cost allocation spread to end customers.

Flaws with the APS approach:

If the fixed costs associated with each individual customer were to be assigned to household related behaviors and technologies such as conserving energy, investing in energy efficiency upgrades or solar PV systems, these actions would never pencil out. Fixed costs are not fixed forever; every cost is variable given the proper time horizon. In the very short run only fuel and some O&M is variable which leads APS to conclude that saving electricity is only worth these short run prices. However, those prices are based on partially paid off assets and provide no glimpse into future expenditures and their real impacts to all ratepayers. Therefore basing value on short term avoided expenses while assigning cost on a long-term basis rigs the equation to favor non-customer sited technologies and conservation related behaviors.

Problems with the rooftop solar industry's approach:

At the same time, 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 eventually become too great. This is because the benefits, even of a perfect technology, do not reduce fixed costs over night. Also, the solar industry included benefits that may never materialize. RUCO is opposed to placing ratepayers on the hook for questionable benefits like the 4.5 cent/kWh resource saving line item in the Crossborder study.

Major issues with Staff's secondary approaches:

Staff does not base their secondary options off any type of rigorous analysis or conclusive answer; rather they offer a range for the Commissioners to essentially pick a number. If this approach were adopted, it would undoubtedly bring great controversy each time new numbers were chosen and yield wildly different policy outcomes depending on the preferences and assumptions selected by the sitting Commission. Second, as RUCO will discuss below, the PPA comparison is set up incorrectly and does not properly judge the two technologies on an equal playing field. RUCO supports making a fair comparison between utility scale DG and rooftop DG; however, RUCO opposes Staff's current approach.

Regulatory reforms that affect DG should carefully balance the costs and benefits by considering the following:

- Rates should be designed to fairly compensate both a) utilities for the cost of services they provide customers and b) distributed generators for the value of services they provide other customers.
- If DG compensation is tied exclusively to average utility costs (i.e. current rates), then DG systems will never be fairly compensated for all the services they provide. This is because any utility investments deferred by DG resources will never materialize in the base rates paid to DG resources via bill offsets and net metering. This is true despite the real value that DG systems can provide other ratepayers by reducing investment needs (and thus future rate increases).
- In other words, correct compensation for DG capacity cannot be exclusively tied to the average or short-run utility cost of generation.
- Since DG resources tend to be long-lived resources, the incumbent utility should compensate sellers at the long-run marginal cost of generation, which is accurately reflected by the levelized cost of energy (LCOE) of an alternative resource (e.g. a gas combustion turbine).
- However, with this in mind, one does not want to overcompensate for benefits that never materialize.
- Also, since the incremental benefits of certain technologies can decline as adoption increases a regular readjustment is needed.
- Finally, even if long-term benefits greatly outweigh costs, there must be an incremental approach to avoid a ballooning near-term fixed cost assignment to non-participating ratepayers.

Exports and Self-Supply are distinct components of DG production and should be valued separately:

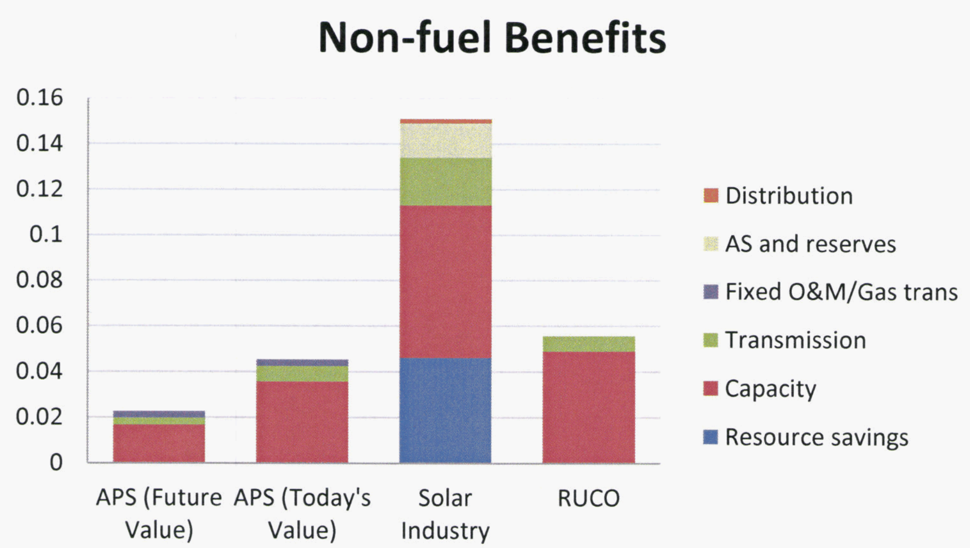
The first step to approaching the issue APS brought forward is to determine the scope of the assessment. Beginning with the DE workshops APS held prior to this proceeding, the company framed this as a larger study of the cost of DG rather than just examining net metering which only pertains to energy exports. RUCO will provide an assessment of both to present a full overview of the matter.

RUCO's analysis shows that a cost shift exists, but is significantly reduced by benefits DG provides (most notably, avoided generation capacity):

RUCO conducted an in-depth analysis and literature review to setup a full cost benefit analysis. RUCO wants to stress that the numbers should not be interpreted as exact values but rather as estimates sufficiently close to reality to make informed policy decisions. Future costs and benefits have inherent uncertainties that make arriving at an exact number with total precision nearly impossible. However, a close approximation can be realized.

Calculation of benefits from avoided generation capacity:

RUCO used a capital cost calculator spreadsheet model employed by the Western Electricity Coordinating Council (WECC) to determine the generation capacity deferred by of a PV systems. The methodology employed was intended to resemble that of SAIC in the APS commissioned study. The difference comes in the fact RUCO took the traditional approach of obtaining a levelized figure rather than a snap shot approach.



Calculation of initial Bill Gap/Cost shift created by DG

Before looking at avoided generation capacity or other potential categories of savings, RUCO determined that the average residential solar customer with a 7 kW system creates around $900 in potential cost shift each year on average (no short-term or long-term benefits included). This figure is then reduced by the benefits that the PV system provides to non-participating ratepayers. Based on our review there is evidence of a $50 near term shift which can be further analyzed as part of the docket RUCO recommends opening. RUCO also recommends studying the longer-term benefits which are outlined below.

Net Cost Shift (adjusting for benefits)

Initial Cost Shift Cost	$891
- Transmission savings	$79
- Generation Savings	$564

= $247 a year in net long term cost shift

After these savings are taken into account, the net long term cost shift would be around $247 per year.[1] A full list of the various components included in this analysis is included in the appendix.

As solar penetration levels increase, the capacity value of the typical DG system (south facing 30 degree tilt) may diminish (assuming no changes in the timing of peak load). For example, if the capacity value was 40% instead of 45%, the gap would be around $25 per month for the average system. Moreover, if the need for new generation gets pushed out into the future this will also increase the charge because the future cost of the plant is discounted to present value. The converse is also true.

The key point of RUCO's approach is that we recognize that rates, costs, and savings are not exact. RUCO does not claim to have the precise number but rather it uses fair estimates of value to send appropriate price signals to the market. RUCO assumptions are included in the appendix and based on assumptions that nearly all the parties (APS, SAIC, and Crossborder) commonly shared when building their respective analyses.

RUCO proposes that the remaining cost shift (net of benefits) be addressed through a capacity-based adjustment to the LFCR mechanisms:

Policy Overview:

RUCO's approach to a solution is built around a simple idea - use market based metrics over a reasonable time horizon to gauge the value of DG to non-solar ratepayers. This method involves a look at capacity value and future generation requirements to determine the value of DG. This creates a price signal to the market that encourages innovation, on-peak production, and ensures a measured deployment of DG.

Providing a solution for REC transfers

The long term net cost shift mentioned above would be covered by a monthly LFCR charge of $3/kW per month. This policy can also solve the REC transfer problem, by

[1] Transmission reflects the value transmission upgrades deferred from DG in the SAIC study adjusted to reflect a 45% capacity value. Generation capacity reflects the avoided generation capacity (modeled as a gas combustion turbine) from DG, which is equal to the capacity value of DG, times the cost of new generation (discounted to present value), e.g. 45% X $10.8 cents/kWh (capacity losses included).

simply allowing customers to choose whether to yield RECs in exchange for full avoided capacity credit, or retain RECs for a smaller capacity credit (and increased surcharge). If one sought to retain RECs, the value for generation could be reduced to reflect the value of environmental attributes of the generation avoided by DG capacity. One way to approximate this value is to base it on the capital cost of NOx reduction equipment on a combustion turbine,[2] which would alter the LFCR adjustment by $3.00 per month. In practice the fixed charge would actually around $10.00 at the first step instead of $7.00.

Phasing of implementation

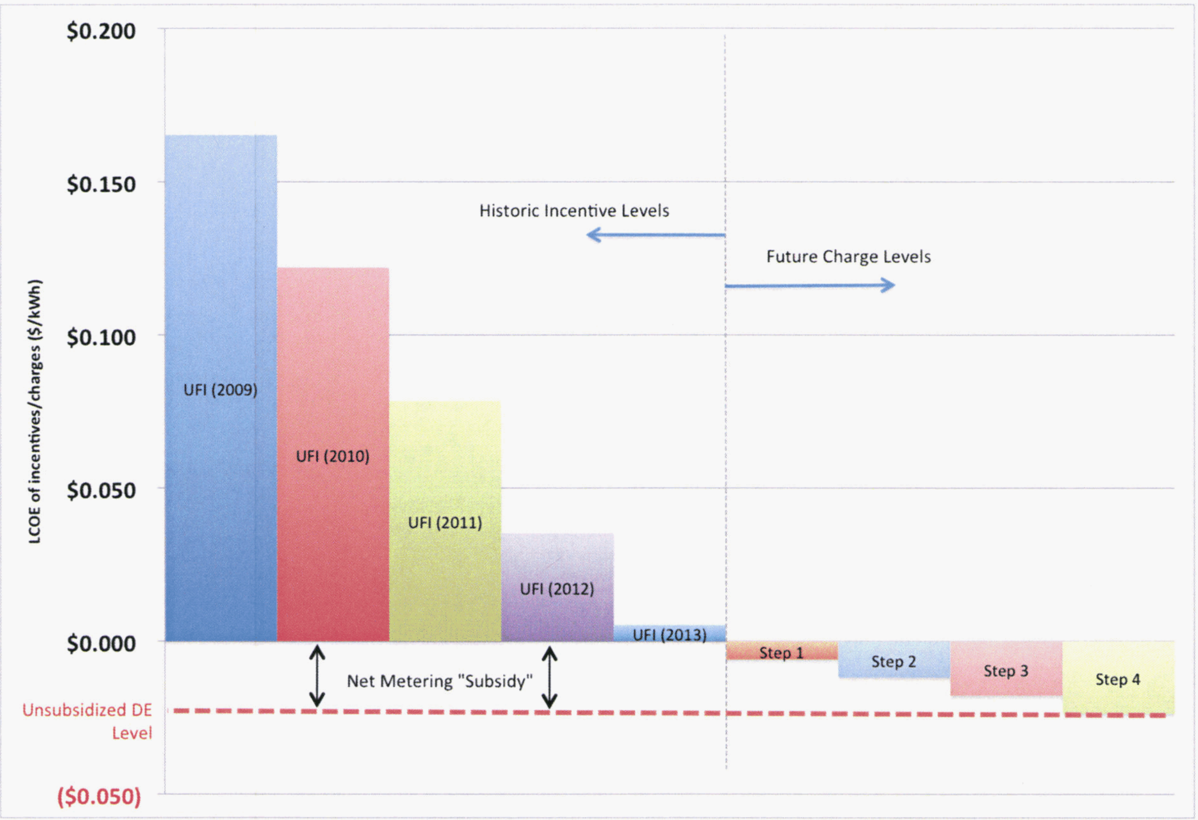
Smooth implementation is critical to the transition. Easing into the new paradigm would allow the industry to plan and prepare to respond to market signals. An example of the phase-in could look like this for a 7 kW system:

	MW Installed	Charge per kW	Charge for average sized system
Step 1	20 MW	$1.00/kW	$ 7.00
Step 2	20 MW	$1.50/kW	$ 10.50
Step 3	20 MW	$2.00/kW	$ 14.00
Step 4	20 MW	$2.50/kW	$ 17.50

Most importantly, this policy is designed to provide regulatory flexibility. The proposed policy empowers the Commission to examine the market and adjust the charge at each yearly if so desired. Alternately, the policy it can be set on "auto pilot" once setup which would require no yearly intervention.

Visual of Charge Phase-in

[2] Based on APS figures and EPA estimates for nitrous oxide equipment on a combustion turbine



RUCO supports a phased implementation of the LFCR adjustment instead of an immediate jump to the full amount

Ratepayers have invested millions into diversifying the electrical system. In doing so, a nationally leading low cost and competitive solar industry was formed. Going from a small incentive to a business stopping fixed charge would cut off this investment right before ratepayers could start to see real benefits. Providing a target for the industry to reach and business certainty along the way is the best type of regulatory environment. Likewise, rate gradualism whether it is for the non-solar ratepayer or the solar ratepayer is also paramount and a principle this Commission has supported in the past.

A phased approach also guarantees balance. There are many other cost shifts happening and likely at higher aggregate amounts (seasonal households, urban and rural, etc.). To subject the local solar industry to such a large cost shift correction without concurrently addressing other known cost shifts does not reflect a fair and balanced approach. Finally, there are longer-term benefits that non-solar ratepayers can expect. Systems can last 25 to 30 years if properly maintained. After year 20 all fixed cost shifts would be recovered above and beyond the benefits the PV system provides.

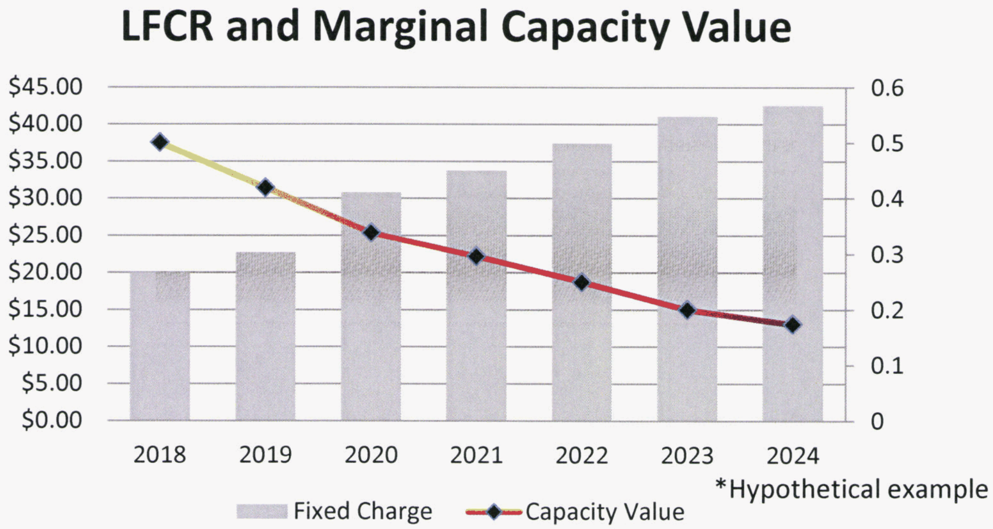
Key points:

- During each 20 MW step, customers would be locked in for 20 years to the applicable fixed charge.

- To avoid excess cost shifting from oversized systems, any system 16 kW and above should be assessed the $3/kW rate.
- Not registering one's system with APS will result in a $3/kW charge.
- Once APS publicly advises that 20 MW of installed capacity has been reached the next trigger will occur one week from that date.
- Periodically the utility should determine the capacity value of solar PV using the method they readily use today to ensure the value of rooftop PV.
- Solar customers on ECT 2 rates would not have a fixed charge.
- This new money collected does not go to APS - it goes to reduce non-solar customer's LFCR charges.
- After $3/kW is reached there is still a near term cost shift occurring. Therefore, if the market can handle further charges this short term cost shift can be mitigated and rooftop solar could actually provide a net benefit for non-solar ratepayers. This will also start to occur at year 20 of the system life under the proposed policy.

As the capacity value for a certain DG technology decreases it sends the correct price signal to the market based on the true value of additional PV capacity, which will encourage the installation of systems that produce more power at peak times. It also sends a price signal if the utility is long or short on generation capacity. As the market starts to send price signals, new technologies can be deployed to meet market demands. This could start with different orientations of panels and end with small storage units that carry solar energy a few hours into peak. Other possible areas of innovation:

- Locational considerations (congested sub transmission zones)
- Tracking systems
- Higher efficiency panels
- Smart inverters and other grid support devices



Some bonuses may also be given for system-wide effects of PV that benefit non-participants, as more data become available.

Deciding if this issue is about net metering or the entire transaction:

The cost benefit analysis that yielded a $3/kW charge looked at the output of the entire PV system, not just exports through net metering. Looking at just exports changes the amount of the fixed charge because the amount of kWhs examined only pertains to system exports. APS estimates that for a typical PV system, exports comprise 20% of the system output with the remaining 80% being self-supply. RUCO estimates that is closer to 40% export, 60% consumption.

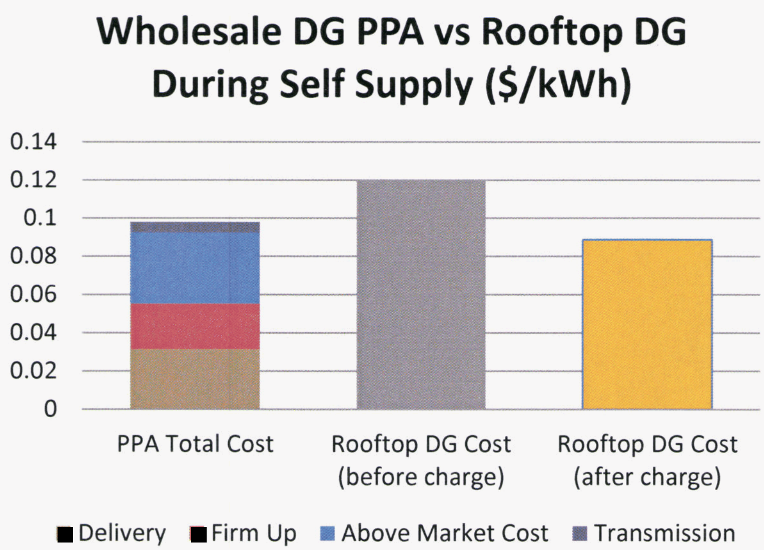
A hybrid of Staff's secondary option and RUCO's option would be to just look at exports and examine the self-supply side in the rate case. Under an exports only scenario, the average system would require around a $4 - $8 per month charge depending on which export rate is used. charge. However, this may continue the lopped sided compensation between rooftop solar on residential rates and a wholesale DG power purchase agreement (PPA).

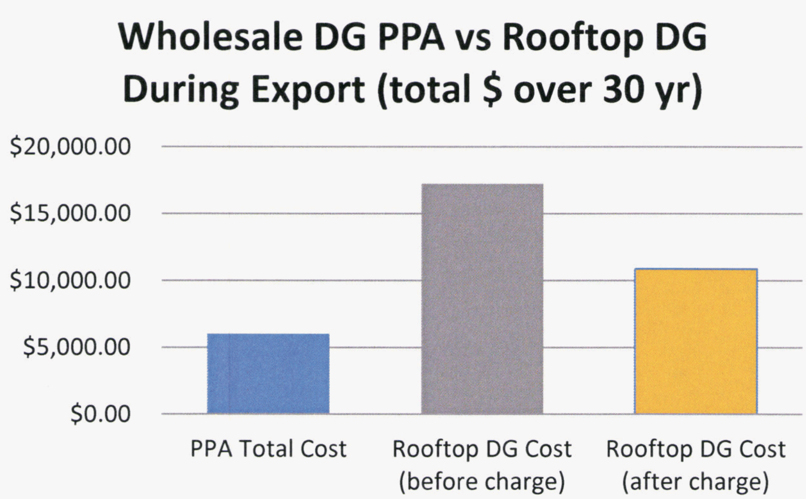
Comparing rooftop solar to a large wholesale DG PPA:

Staff proposal compares a PPA price to the retail rate for a residential customer. RUCO disagrees with this methodology. Rooftop solar has two modes: self-supply and export. Self-supply is very similar to a full retail product or lower capacity value energy conservation – It is used instantaneously by the home and does need transmission or distribution. The "export mode" uses part of the distribution system and resembles a transaction similar to a PPA.

RUCO delved into this comparison to put the two technologies on equal platform. RUCO did find that the wholesale DG PPA was less expensive. During self-supply the PPA is ~20% cheaper than rooftop solar. During export, the PPA is significantly cheaper. Once totaled, the difference was right in the range of the value gap identified earlier ~$20 per month for the average sized system given around a 65% to 70% self-consumption rate. This assumes a comparison to a single axis tracker with an 8.5 cent/kWh 30 year PPA.[3] The methodology employed was similar to that used in the 2012 APS IRP plan.

[3] Assumes a 4.8 cent/kWh market cost of conventional comparable generation (MCCCG)





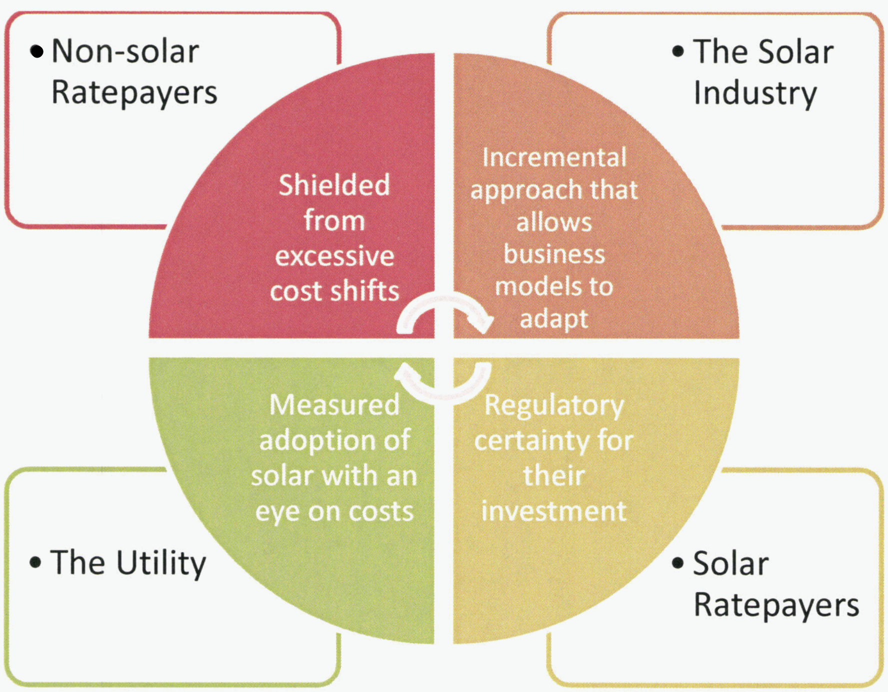
RUCO recommends against using comparisons between wholesale and customer side of the meter transactions to determine policy details. It should be used to check reasonableness but not to identify specific numbers. The comparison is messy and one assumption change can yield dramatically different outcomes.

Conclusion:

The only way to gauge the monetary equity of the current system is to determine the value of distributed generation PV. As discussed above and shown in the appendix, RUCO conducted a rigorous analysis of the costs and benefits. One thing is clear, rooftop solar PV is not the cell phone yet. It is more akin to a mobile phone that needs to be plugged into the wall at all times. Therefore, RUCO took a conservative view on the benefits. RUCO admits that there is other less easily quantifiable benefits or even intangible benefits to DG but RUCO focused on what is immediately valuable to the grid and in turn non-participating ratepayers. In doing so, RUCO balances the concerns of all parties and protects ratepayers from a snowballing of fixed cost shifts. Finally, under any proposal the ACC picks, APS must be required to file a rate case – the sooner the better.

In sum, RUCO policy accomplishes the following:

1. It develops a uniform methodology for other Arizona utilities to follow while taking into account the uniqueness of their service territory (TEP, UNSE, etc.)
2. It can apply to other technologies
3. It recognizes solar's value (conservatively)
4. It recognizes the cost shift and contains it with money going to ratepayers not the utility
5. It takes into account changes in solar's value over time
6. It levels the playing field between solar technologies
7. It can be designed to capture RECs
8. Net metering still exists in its current form
9. Underlying rate structures do not need to change to guard against solar adoption
10. It provides the Commission with much flexibility



Appendix

Model and Assumptions for Computing the Net Cost Shift:

The Net Cost Shift will be diminished if solar contributes to the avoidance of fixed costs such as new generation capacity or transmission upgrades. The following illustrates one way to calculate avoided fixed costs on a per kWh basis using inputs and assumptions specific to Arizona Public Service Company (APS). Inputs to the calculation can be easily modified as conditions change on the utility's system, to update the fixed charge over time.

1. *Pro Forma Tool for Modeling Fixed Costs*: The fixed cost components of any incremental generation capacity can be easily calculated using a *pro forma* accounting tool. One such tool is the 2012 TEPPC Generation Capital Cost Calculator ("GCC"), which was developed by E3 for the WECC interconnection-wide 2013 Transmission Plan. The tool and supporting documentation can be downloaded from the following URL: http://www.wecc.biz/committees/BOD/TEPPC/Pages/2013Plans_Tools.aspx

2. *Model Inputs*: The assumed incremental generation unit displaced by solar PV is an aero-derivative gas combustion turbine (CT). The following assumptions were used as inputs to the GCC to represent the CT-equivalent of a rooftop solar PV system for APS:

Assumption	Units	Value	Source/Notes:
Installed Capacity	MW	0.007	7kW was assumed as typical size of a rooftop PV system. The installation size does not affect the LCOE results, but is useful to include in the model for other purposes.
Capacity Factor	%	22.16%	4/11/2013 workshop; PV capacity factor based on 1650 kWh/kW per year.
Total Installed Cost (Generation)	$/kW	$1,136.00	SAIC 2013 Study; Data & Assumptions-APS15198
Generation-related Transmission Costs	$/kW	$206.00	SAIC 2013 Study; Data & Assumptions-APS15198
Total Unit Cost (Fixed O&M)	$/kW-yr	$5.46	SAIC 2013 Study; Data & Assumptions-APS15198
Annual Escalation (Fixed O&M)	%/yr	2.5%	SAIC 2013 Study; Data & Assumptions-APS15198 (based on inflation rate)
Financing Lifetime	yrs	32	Table 14 of APS 2012 IRP; http://www.aps.com/library/resource%20alt/2012ResourcePlan.pdf
MACRS Term	yrs	15	Table 14 of APS 2012 IRP; http://www.aps.com/library/resource%20alt/2012ResourcePlan.pdf
Equity Share	%	53.94%	SAIC 2013 Study; Data & Assumptions-APS15198
Debt Share	%	46.06%	SAIC 2013 Study; Data & Assumptions-APS15198
Debt Cost	%	6.5%	SAIC 2013 Study; Data & Assumptions-APS15198

Equity Return	%	10.0%	SAIC 2013 Study; Data & Assumptions-APS15198
Federal Tax Rate	%	35.00%	Default value of TEPPC model
State Tax Rate	%	6.94%	Adjusted so that combined value matches SAIC study inputs
Combined Tax Rate	%	*39.51%*	SAIC 2013 Study; Data & Assumptions-APS15198
Current Year	-	2013	
Generator In-Service Date	-	2017	Based on approximate year of new capacity need as indicated in in APS 2012 IRP.

The GCC default values were used for nearly all inputs, except those indicated above. No property taxes or insurance premiums were modeled, so these values were set to zero.

3. *Generation Capacity*: The IOU Proforma tab of the GCC was used to find the LCOE (in $/MWh) for the fixed cost components (the sum of Capital Costs and Fixed O&M) associated with generation deferred by PV. The IOU Proforma tab was modified to include a delayed in-service date that corresponds to the year of capacity need as indicated by the utility's load and resource plan.

4. *Generation-related Transmission*: The Transmission costs associated with deferred generation were calculated using the Tx Proforma tab of the GCC. The Tx Proforma tab was modified so that the "Total System Cost" of the transmission project cost was set equal to the product of the "Installed Capacity (kw)" and the "Generation-related Transmission Costs ($/kW)" values. A LCOE value was then calculated using the same methodology as is used for capacity; the NPV of revenue requirements is divided by the NPV of energy production.

5. *Capacity Value*: Using the assumptions specified above, the total fixed cost component of new generation capacity (including associated transmission) for APS was determined to be approximately $0.109 per kWh or $0.0489 after capacity value adjustment. This fixed cost value is then multiplied by the current capacity value of a rooftop PV. For APS's system, this capacity value is approximately 45%, at present, and corresponds to the Effective Load Carrying Capability (ELCC) calculation[4]. An 11.7% rate on capacity losses was included in the overall value. This value is expected to change if solar penetration increases, (or decreases) or the peak load hour shifts. While capacity value is projected to decrease over time, the true direction and magnitude of this change is unknown.

6. *Other Transmission and Distribution*: Transmission and distribution deferrals that are not related to generation projects were not directly calculated. Instead, we assumed the same avoided transmission cost calculated in the SAIC 2013 Study (about

[4] ELCC depends on several factors, such as load forecasts, that include uncertainties. Since ELCC is a fundamental component of determining the capacity value, the methods used to determine this for DG require careful scrutiny and transparency.

$0.0034/kWh) but adjusted to reflect a 45% capacity value. However, we note that avoided subtransmission costs could be more precisely determined for any PV system using the methodology described above and three additional pieces of information:

- Total cost of the next planned transmission upgrade in region of PV system location
- Total MW of solar PV necessary to defer the transmission project
- Planned in service date and deferred in service data.

RUCO is open to different numbers related to transmission deferral. The number from SAIC is a snap shot figure – not levelized. We use it because the number comes in half way through the PV system's life span therefore it could be close to a levelized (LCOE) figure.