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BEFORE THE ARIZONA CORPORATION COMMISSION

BOB STUMP
Chairman
GARY PIERCE
Commissioner
BRENDA BURNS
Commissioner
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Commissioner
SUSAN BITTER SMITH
Commissioner

Arizona Corporation Commission
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IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S APPLICATION FOR APPROVAL OF NET METERING COST SHIFT SOLUTION	DOCKET NO. E-01345A-13-0248 DECISION NO. 74202 ORDER

Open Meeting
November 13 and 14, 2013
Phoenix, Arizona

BY THE COMMISSION:

FINDINGS OF FACT

1. Arizona Public Service Company ("APS") is certificated to provide electric service as a public service corporation in the State of Arizona.

2. On July 12, 2013, APS filed an application ("Application") for approval of a Net Metering Cost Shift Solution. Subsequent to APS's filing, several parties requested and were granted intervener status in this docket, including The Alliance for Solar Choice ("TASC"), Lewis M. Levenson, Tucson Electric Power Company, UNS Electric, Inc., the Residential Utility Consumer Office ("RUCO"), the Solar Energy Industry Alliance ("SEIA"), Western Resource Advocates, and the Interstate Renewable Energy Council, Inc. ("IREC").

3. TASC filed a formal Protest in the Docket on July 29, 2013, urging the Arizona Corporation Commission ("Commission") to reject APS's application and institute an alternative proposal. On August 20, 2013, SEIA filed a Protest and Motion to Dismiss, asserting that there is no cost-shift between customer classes as a result of net metering ("NM"), and that the Application

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represents an attempt at ratemaking outside of a general rate case. TASC joined SEIA's Protest and Motion to Dismiss on August 30, 2013.

4. IREC filed a formal Protest in the Docket on August 29, 2013, asserting that the instant docket is not the appropriate venue for analysis of APS's NM program. IREC states that further discussion and analysis is required to obtain a comprehensive understanding of the benefits and costs of distributed solar photovoltaics in Arizona. IREC urges the Commission to reject APS's Application and defer discussion of its proposals to a future general rate case.

5. Numerous letters from customers voicing both support and opposition regarding NM programs in general, and APS's proposed NM cost-shift solutions in particular, have been filed in this Docket.

Background

6. APS's Application states that rooftop solar installations have increased significantly each year in APS's service territory since January 2009. The Application states that as of January 2009, there were approximately 900 systems installed. As of June 2013, that number had grown to over 18,000 and continues to grow by approximately 500 new rooftop solar systems each month. Much of this recent growth is attributable to Arizona's Net Metering Rules, which were implemented in May 2009, under Title 14, Chapter 2, Article 23 of the Arizona Administrative Code ("A.A.C."). The impetus for establishing Net Metering Rules was to incent the deployment of customer-sited DG.

7. As defined by these rules, NM allows electric utility customers to be compensated for generating their own electric energy from renewable resources, fuel cells, or Combined Heat and Power systems (collectively "distributed generation" or "DG"). If the customer's energy production exceeds the energy supplied by the electric utility during a billing period, the customer's bill for subsequent billing periods is credited for the excess generation. That is, the excess kWh generated during the billing period is used to reduce the kWh billed by the electric utility during subsequent billing periods. Effectively, this credit process compensates the customer (and incents the development of distributed generation) by requiring the electric utility company to acquire the customer's excess generation at the customer's current effective retail rate. In order to

prevent abuse of the NM incentive, the Arizona NM Rules limit the size of customer DG systems to a maximum of 125 percent of the NM customer's total connected load.

8. Once each year (or for a customer's final bill upon discontinuance of service), the electric utility credits the customer for the balance of any remaining excess kWh. The payment for the purchase of these year-end excess kWh is at the electric utility's annual average avoided cost, which is specified on the electric utility's NM Tariff. A.A.C. R14-2-2302(1) defines avoided cost as "the incremental cost to an Electric Utility for electric energy or capacity or both which, but for the purchase from the NM facility, such utility would generate itself or purchase from another source."

9. As the participation in Arizona NM has grown, so have APS's concerns regarding the issue of cross-subsidization between customers that participate in NM programs and those that do not. APS asserts that while the NM customers benefit from the NM policy incentives, the non-participants are burdened with a disproportionate share of the subsidies required to fund the NM incentives. In the case of APS's system, this cross-subsidization is most apparent for the Residential consumer class. APS states that, on average, the cost shift each year is approximately $1,000 per residential NM system, with total annual costs shifting to non-NM customers of approximately $18 million. This alleged cross-subsidy is the basis of APS's Application.

The Application

10. APS filed the instant Application on July 12, 2013, in an effort to provide a solution to the NM cost-shift issue. The broader issue of DG cross-subsidization has been mentioned in a past rate case, specifically APS's 2005 general rate case[1]. APS's most recent (2011) general rate case did not specifically address the NM cross-subsidization issue.

11. APS emphasizes that the instant application is proffered as a solution to the cross-subsidization of customers with Net-Metered DG systems by those customers without such systems. In this context, APS asserts that the issue is one of fairness to all customers and is not related to a loss of revenue by APS because of NM.

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[1] *See e.g.*, Decision No. 69663, pp. 87-89 (June 2007).

12. In preparation for filing the Application, APS hosted a multi-session technical conference ("Technical Conference") in the first half of 2013 to evaluate the costs and benefits of Distributed Energy[2] and NM. Over the course of the Technical Conference, 175 people attended representing a diverse group of stakeholders including solar installers, developers, policy advocates, customers, utility representatives, academics, consultants, researchers, consumer advocates, and Commission representatives. The results of the Technical Conference, including detail regarding the various stakeholder perspectives, were attached to the Application as Exhibit 4.

13. Informed by input received at the Technical Conference, together with analyses conducted by other jurisdictions, and an update of a previous study of DG benefits, APS developed a range of potential solutions which fell into two broad categories. The first solution group were options that continued the use of NM and emphasized the use of the basic service charge, a demand charge, or a standby charge.

14. The second group of potential solutions involved moving from NM to a mechanism by which DG customers pay for all of the energy they consume, but receive a bill credit for 100 percent of the energy produced by their DG system. The key variable in this group of potential solutions concerned the method for setting the price paid to customers for the DG energy they produced. Those methods generally involved setting either a market-based price, or a price based on values and non-market concepts.

15. Drawing from each group, APS proposes two possible solutions and requests that the Commission select one of the proposed solutions. Based on the Commission's selection, any new APS residential customer installing DG would either: (1) take service under APS's existing ECT-2 rate and use NM ("the NM Option"); or (2) take full requirements service under the customer's existing rate and receive a bill credit for 100 percent of the DG system's production at a market-based price for power ("the Bill Credit Option").

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[2] In this Memorandum, the terms "Distributed Generation ("DG")" and "Distributed Energy" or "DE" are used interchangeably.

- <u>The NM Option - ECT-2 Plus NM</u>

  Under this option, all residential customers installing a new DE system would only be eligible to take electric service under APS's existing ECT-2 rate. The ECT-2 rate is a demand-based rate with Time-of-Use ("TOU") features. APS states that the ECT-2 rate better balances the collection of fixed costs between usage-based energy charges and demand-based charges, and would allow APS to more accurately charge DE customers for the services they use.

- <u>The Bill Credit Option</u>

  Under this option, customers could remain on any APS rate plan for which they are otherwise eligible. Instead of NM, APS would compensate customers through a bill credit for all of the power produced by their DG system. The amount of credit would be based on the forward market at the Palo Verde hub with adjustments. APS asserts that this price would send a more accurate price signal for the true cost of the electrical services provided to potential DG customers.

16. Under either option, APS proposes that all existing NM customers would be grandfathered under the customer's existing arrangement. Specifically, APS proposes grandfathering existing rate constructs (i.e. a customer's existing rate and use of NM) for residential customers who either have DG installed on their homes now, or who submit an application and a signed contract with a solar installer to APS by October 15, 2013. The grandfathering would extend for a maximum of 20 years from the effective date of the Commission's decision in this matter and would not be transferable to a new customer at the same premise.

17. APS states "...both options will change the economics of DE transactions and could result in a slower pace of residential rooftop solar installations." APS suggests that direct cash up-front incentives ("UFIs") could be authorized by the Commission to encourage additional DE penetration. APS favors the use of UFIs as they provide a transparent, flexible means to incentivize DE installations.

18. APS's Application is supported by the direct testimony of Jeffrey Guldner, Vice President, Customers and Regulation, Gregory L. Bernosky, Manager of Renewable Energy, and Charles A. Miessner, Pricing Manager.

19. APS concludes its application by requesting that the Commission:

- Select either the NM Option or the Bill Credit Option;

- Grandfather the rates and use of NM by existing and immediately pending DE customers;
- Implement an incentive structure as described in the Application and attached testimony, should the Commission choose to order the direct payment of cash to incentivize residential DE installation;
- Address this matter on an expedited basis; and
- Grant any waivers or other forms of relief that the Commission deems appropriate.

Staff Analysis

20. Arizona's NM policy is designed to incent the deployment of customer-sited DG through the use of NM bill credits at the customer's retail rate, the NM method favored by a majority of states allowing NM. The recent rapid increase in NM installations, despite declining up-front incentives, validates the success of the NM incentive.

21. With increasing levels of DG penetration, the potential of shifting costs from customers with DG systems to those customers without such systems becomes apparent. As more customers offset a portion of their monthly bills by using energy produced by their DG systems, they purchase less energy from the utility. Because residential rates are typically designed to recover much of the utility's fixed costs[3] through volumetric energy rates, DG customers effectively pay less of these fixed costs. The additional fixed costs then must be picked up by non-DG customers either through higher energy rates or through other mechanisms such as APS's Lost Fixed Cost Recovery mechanism ("LFCR"). The magnitude and significance of this cost shift increases as more and more DG systems are added to the utility's system. However, base rates are not changed until the utility's next rate case. Therefore, for systems installed after APS's last test year (2010), the cost shift has not yet occurred (except for that in the LFCR).

22. Based on responses to Staff's several Data Requests, APS provided a table of residential and commercial DG incentive applications and installations from January 2011 through July 2013. These data responses confirm APS's assertion that DG installations have risen over the

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[3] Fixed costs typically recovered through volumetric energy rates include costs associated with the utility's generation, transmission and distribution infrastructure.

reporting period to a current rate of approximately 500 per month. APS also provided additional data that indicate the magnitude of the cost shift within the residential ratepayer class is within the range of $800 to $1,000 per year per DG customer.

23. APS also supplied Staff with a map depicting the location of all customer-sited DG systems within its service territory. Staff notes that while the distribution of DG systems appears relatively even across the urbanized areas within APS's service territory, there may be a tendency for DG systems to be located in areas of higher income for two reasons: first, financial barriers to entry (i.e. up-front costs for purchased systems and credit scores for leased systems); second, NM benefits are greater for high energy users who would otherwise consume energy in higher-priced tiers than they are for low energy users who consume energy in lower priced tiers.

The Value of DG

24. APS's application focuses on the costs associated with increasing levels of DG installations. However, integral to the discussion of DG is the question of what *value* DG offers to APS's electric system and thereby to the customers served by that system. Staff believes that there are two forms of value inherent in DG systems.

25. The first form of value we call "Objective Value" which we define as measurable benefits. An example of Objective Value is avoided fuel costs. Even objective value can be difficult to predict in future time periods.

26. The second form of value we call "Subjective Value". Subjective Value requires the subjective assignment of monetary values to anticipated future benefits that are not easily measureable. Examples of Subjective Value offered by DG are increased grid security and air quality improvements.

27. While Objective Values of DG may be determined more easily, even though Objective Values can be difficult to predict in future time periods, the assignment of Subjective Values is by its nature often controversial. Complicating the debate is the wide variety of approaches and methodologies used by various parties in their analysis of this issue. These variations in study approach and conclusions are evident from two recent studies that have been filed in this docket.

28. The study prepared by SAIC Energy, Environment & Infrastructure, LLC ("SAIC Report"[4]) on behalf of APS states that the primary value of DG is principally the avoided fuel costs. In contrast, the study prepared by Crossborder Energy ("Crossborder Study"[5]) and filed in the docket by TASC finds that the benefits of DG on the APS system exceed the costs, to the extent that TASC recommends the creation of a System Benefit Credit mechanism to further compensate DG customers beyond the existing NM incentive.

29. A recent report by the Electricity Innovation Lab and the Rocky Mountain Institute[6] reviewed 15 distributed PV ("DPV") benefit/cost studies that were prepared by utilities, national laboratories, and other organizations. The goal of this study was to "...assess what is known and unknown about the categorization, methodological best practices, and gaps around the benefits and costs of DPV...". This study concluded that none of the 15 studies reviewed had comprehensively evaluated the benefits and costs of DPV. The study further states that "There is a significant range of estimated value across studies, driven primarily by differences in local context, input assumptions, and methodological approaches." The study states that there is significant disagreement over capacity value methodologies and the "...currently unmonetized values including financial and security risk, environment, and social value."

30. Staff concludes that assignment of a Subjective Value to the presently unmonetized components of DG value is a public policy issue. Such public policy decisions necessarily require a subjective assignment of values consistent with policy goals.

31. Staff further concludes that the objective value aspects of DG to the APS system can best be determined in the context of a general rate case when all of APS's costs can be considered. Therefore, a precise determination of DG costs and benefits to APS's system is beyond the scope of Staff's analysis of the instant application. Instead, Staff has developed a range of proxy values for DG as a basis for its alternative recommendations (see *Staff*

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[4] SAIC Energy, Environment & Infrastructure, LLC, *2013 Updated Solar PV Value Report*, dated May 10, 2013, and filed in this docket May 17, 2013.

[5] Crossborder Energy, *The Benefits and Costs of Solar Distributed Generation for Arizona Public Service*, dated Mayy 8, 2013, and filed in this docket on July 2, 2013.

[6] Rocky Mountain Institute, *A Review of Solar PV Benefit & Cost Studies*, undated.

Recommendations section below) which are intended to be bridge solutions that begin to address the cost-shift issue.

32. Once the costs and benefits of DG have been adequately quantified and valued, the allocation of these costs and benefits equitably among customers is a matter of rate design. Recovery of fixed costs through volumetric rates may conflict with the intra-rate-class equity of NM. Staff further notes that the equitable distribution of DG costs and benefits ideally requires all NM customers to have some form of demand-based charges. Development of equitable rate structures that address the inherent disconnect between NM and volumetric rates can best be accomplished in a general rate case.

33. Staff notes that during general rate cases and as part of the rate design process, it is common practice to analyze matters of cost-shifts and cross-subsidizations within individual rate classes. Some rate designs commonly utilize subsidies to promote various public policy goals. The discount provided to low-income customers is a classic example of this intentional cross-subsidy. Another common example is the subsidy given to rural customers at the expense of urban customers to cover the higher cost of service to the more dispersed rural customers. Staff believes that the cross-subsidy discussed in the instant Application has explicit public policy considerations, and therefore would be most appropriately addressed in the setting of a general rate case.

Staff's Analysis of APS's Proposed Alternatives

ECT-2 Plus NM Option

34. The ECT-2 Plus NM Option relies on a demand charge within the ECT-2 rate schedule to partially collect fixed costs. However, APS notes that because the ECT-2 rate also partially relies on usage charges to collect fixed costs, this Option is an imperfect solution. In addition, the ECT-2 Plus NM Option is not revenue neutral, as the rate's demand charge would collect additional revenue. APS has not proposed a method by which all additional revenue would be returned to non-DG ratepayers. In addition, Staff believes that forcing certain customers to use a specific rate schedule removes a basic choice from the customer – the choice of the rate schedule

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that works best for their usage pattern and lifestyle. The impact of the ECT-2 Plus NM Option proposal to the average APS residential DG customer is presented below in Table I.

35. While Staff does not recommend the ECT-2 tariff for all solar customers, customers that voluntarily select this rate should be exempt from any additional cost-shift surcharges as the ECT-2 rate design addresses the collection of lost-fixed costs through a demand charge.

Bill Credit Options

36. The Bill Credit Option is very similar to a "buy all – sell all" Feed-In-Tariff ("FIT"), which is quite different than a NM arrangement. FITs are typically implemented to incent generation facilities with higher production output than is typically seen in residential DG, and are more often directed towards Qualifying Facilities ("QF") as defined under Public Utility Regulatory Policy Act ("PURPA"). Staff notes a docket filing by TASC[7] that opines that a residential FIT may have negative (and unexpected) tax implications for the residential FIT customer.

37. The Bill Credit Option is not equivalent to a NM arrangement because it denies the residential customer the right to offset energy purchases from the utility with self-generation on a one-to-one basis. Staff believes that residential customers should have the ability to receive such an offset. In addition, the Bill Credit Option is not revenue-neutral and APS again offers no guidance on how additional revenues produced under this Option would be returned to non-DG ratepayers.

38. The estimated bill impact of APS's two proposed options to the average APS residential DG customer is presented below in Table I. Note that in this Table, the terms "IB Rate" means inclining block rate, and "TOU E Rate" means time-of-use energy rate. These terms are intended to broadly describe the two basic types of residential rate designs utilized by APS.

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[7] See the letter filed August 16, 2013 in this docket from Skadden, Arps, et al filed by TASC that states in part: "Under current law, residential FITs jeopardize the Section 25D credit because electricity generated by such residential solar systems is sold to the utility, rather than used in a personal residence of the taxpayer. Further, payments received by a taxpayer under FITs are likely includable in taxable gross income." TASC summarizes this matter with the statement: "…such a requirement will essentially exchange federal tax credits for federal taxes, reversing the existing flow of money into Arizona."

Table I
Estimated Customer Bill Impact

	Current NM Program			Proposed Option - ECT-2 Rate			Proposed Option - Bill Credit		
IB Rate	Summer	Winter	Annual	Summer	Winter	Annual	Summer	Winter	Annual
Bill before solar (w/tax)	$275.22	$ 115.91	$ 195.57	$ 275.22	$ 115.91	$ 195.57	$ 275.22	$ 115.91	$ 195.57
Bill with solar	$ 92.64	$ 30.65	$ 61.65	$ 156.78	$ 82.95	$ 119.87	$ 235.22	$ 85.91	$ 160.57
Savings	$182.58	$ 85.26	$ 133.92	$ 118.44	$ 32.96	$ 75.70	$ 40.00	$ 30.00	$ 35.00
% savings	66.3%	73.6%	68.5%	43.0%	28.4%	38.7%	14.5%	25.9%	17.9%
TOU E Rate	Summer	Winter	Annual	Summer	Winter	Annual	Summer	Winter	Annual
Bill before solar (w/tax)	$224.63	$ 115.13	$ 169.88	$ 224.63	$ 115.13	$ 169.88	$ 224.63	$ 115.13	$ 169.88
Bill with solar	$ 72.19	$ 40.48	$ 56.34	$ 156.78	$ 82.95	$ 119.87	$ 184.63	$ 85.13	$ 134.88
Savings	$ 52.44	$ 74.65	$ 113.55	$ 67.85	$ 32.18	$ 50.02	$ 40.00	$ 30.00	$ 35.00
% savings	67.9%	64.8%	66.8%	30.2%	28.0%	29.4%	17.8%	26.1%	20.6%

39. APS suggests that the continued use of UFIs could be used to help offset any slowdown in DG installations caused by APS-proposed NM cost-shift solution options. Staff believes that the level of UFI incentives should not be established in this docket, but rather in APS's annual Renewable Energy Standard Tariff ("REST") implementation plan.

40. Both NM cost-shift solutions proffered by APS include provisions for "grandfathering" the NM situations of existing (and customers that apply before APS's suggested deadline of October 15, 2013) NM customers. Under APS's grandfathering concept, NM customers would maintain their existing rate constructs (i.e. a customer's existing rate and use of NM) for a maximum of 20 years from the effective date of the Commission's decision in this matter and would not be transferable to a new customer at the same premise.

41. Based on the analysis discussed above, Staff recommends that the Commission not approve either of APS's proposed NM cost-shift solutions.

42. Staff further recommends that any consideration of grandfathering existing NM situations to existing NM customers should view the grandfathering as pertaining to the DG system and premises where the DG system is sited (in other words, "runs with the land"), versus a "right" that resides with a specific customer.

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Stakeholder Proposals

43. Three alternative cost-shift solution proposals have been received from interveners in this case. The first alternative proposal was docketed on July 2, 2013, by TASC. TASC proposes the creation of a System Benefit Credit to reward DG for the excess value that TASC believes DG customers provide to the grid. The TASC proposal relies on the Crossborder study. The TASC proposal suggests that credits could be either demand (kW) or energy (kWh) based and would be paid over the life of the DG system, rather than upfront, in order to link the credit to the long-term performance of the DG system. The credit could be implemented through the existing NM tariff, or through a new rate rider schedule, similar to APS's critical peak pricing rider (CPP-RES). TASC concludes its proposal by suggesting that details of the System Benefit Credit could be developed collaboratively by the Commission, APS, TASC, and other stakeholders.

44. Staff believes that establishing a System Benefit Charge outside a rate case would have to be established as part of the incentives available through the Renewable Energy Standard Tariff ("REST") program.

45. The second alternative proposal was informally proffered to Staff by RUCO during several meetings in late July and early August 2013. RUCO proposed the establishment of a market-based adjustor mechanism that links the value of DG to a defined set of market metrics. Implementation of this cost adjustor would be through APS's REST Implementation Plan and would be updated annually. RUCO states that this approach could be utilized by all utilities that are subject to the Commission's REST Rules.

46. The third alternative proposal was proffered by IREC in its Protest filing. IREC suggests that the Commission and stakeholders develop a common set of assumptions and inputs regarding the costs and benefits of NM during APS's next general rate case. Utilizing the common set of assumptions and data inputs, IREC suggests that a neutral third party, such as Clean Power Research, be retained to model the benefits and costs of NM on the APS electric system. IREC asserts that this modeling would produce a fair and neutral set of data upon which the Commission and stakeholders could rely to evaluate APS's NM program.

47. Unfortunately the three suggested options set forth above present legal challenges that would be avoided if the Commission were to adopt one of Staff's recommended options discussed below.

48. Staff believes that the development of a common set of assumptions and inputs will be fundamental in any future analysis of NM costs and benefits as in APS's next rate case.

49. In light of the record before us, we find that the proliferation of DG installations results in a cost shift from APS's DG customers to APS's non DG residential customers absent significant changes to APS's rate design.

The NM Cost-Shift Issue in Other Jurisdictions

50. Arizona is not unique in confronting the NM cost-shift issue. Currently, some form of NM has been adopted in 43 states. Several other states that have experienced relatively rapid penetration of customer-sited DG have recognized the cost-shift issue and addressed it in varying ways. A brief synopsis of several recent Public Utility Commission actions and utility company programs that have parallels to the cost-shift issue in Arizona, and that may help inform the Commission on its decision on the instant Application, is located in Appendix I of the Staff Report.

Staff Recommendations

51. Staff recommends that the Commission not approve either of the NM cost-shift solutions proffered by APS in the instant application for the reasons discussed above. Instead, Staff recommends that no changes be made at this time, but instead, this issue be evaluated during APS's next rate case. However, if the Commission wishes to address this issue immediately, Staff proposes two alternative recommendations as bridge solutions that begin to address the NM cost-shift issue until such time as the Commission is able to address the issue more completely in APS's next rate case.

Address in Next Rate Case

52. Staff believes that any cost-shift issue created by NM is fundamentally a matter of rate design. The appropriate time for designing rates that equitably allocate the costs and benefits of NM is during APS's next general rate case. Data on all of APS's costs are available within a

rate case. In addition, the Commission has more options available within a rate case than it has outside of a rate case. Therefore, Staff recommends that the Commission take no action on the instant application and defer the matter for consideration during APS's next rate case.

53. Staff further recommends that the Commission hold workshops with all stakeholders to help inform future Commission policy on the value that DG installations bring to the grid. In addition, Staff recommends that within the workshops, the Commission investigate the currently non-monetized benefits of DG with the goal of developing a methodology for assigning DG values, as the NM cost-shift issue will be faced by all Arizona electric utilities as the penetration level of DG increases in each of the companies' individual service territories. The Commission may achieve this goal by opening a generic docket to investigate the value of DG and hold workshop meetings to obtain stakeholder input.

54. Staff believes this recommended course of action is the most effective and appropriate method of dealing with the APS NM cost-shift issue. However, should the Commission wish to apply the concept of rate-making gradualism to this matter, Staff offers the following two alternative recommendations as bridge solutions that begin to address the NM cost-shift issue until the matter can be more comprehensively resolved in a future general rate case.

55. Additionally, Staff believes that its alternative recommendations, which both involve adjustments to APS's Lost Fixed Cost Recovery ("LFCR") adjustor mechanism, lend themselves to implementation outside of a rate case. The provisions regarding the LFCR, which was adopted by Decision No. 73183 (May 24, 2012), expressly acknowledge that the Commission may review the LFCR and that suspension, termination or modification may result from such review. Likewise, Staff's two recommendations do not change the overall lost fixed cost revenues that APS recovers through the LFCR adjustor mechanism. Rather, they adjust which customers pay lost fixed costs through the LFCR. Consequently, Staff's two alternative recommendations are also revenue neutral.

56. We agree with Staff's view that the issues presented herein will likely need to be addressed and considered as part of APS's next rate case filing. This is also the view expressed by RUCO in its comments to the docket. Therefore, the sooner APS makes its filing consistent with

the provisions of Decision No. 73183, the sooner the important issues arising from these matters can be considered in the context of a full rate case.

Staff Recommended Alternative #1

LFCR Flat Charge for All New DG Customers

57. Staff's first recommended alternative utilizes APS's LFCR adjustor mechanism that was approved by the Commission on May 24, 2012, under APS's last rate case Decision No. 73183. The LFCR adjustor provides for the recovery of lost fixed costs, as measured by revenue, associated with the amount of energy efficiency savings and DG that is authorized by the Commission and determined to have occurred. Costs recovered through the LFCR include the portion of transmission costs included in base rates and a portion of distribution costs, other than what is recovered by (1) the Basic Service Charge, and (2) 50 percent of demand revenues associated with distribution and the base rate portion of transmission. The LFCR adjustment is calculated by dividing Lost Fixed Cost Revenue by the Applicable Company Revenues. This adjustment percentage is applied to all customer bills, excluding both those on excluded rate schedules and those that have chosen the Flat Charge of the standard LFCR calculation. The LFCR adjustment collection is subject to an annual one-percent year over year cap based on Applicable Company Revenue.

58. The LFCR adjustor provides a Flat Charge provision for customers that prefer to pay through an optional Basic Service Charge. Rather than calculate the LFCR charge as a percentage of a customer's total bill, the Flat Charge provision sets the LFCR charge, based on a customer's kWh consumption, times the number of days in the month. Most customers (both with and without DG) currently select the percentage of bill LFCR charge because it is currently less expensive than the Flat Charge option. The LFCR Flat Charge tiered consumption rates are presented in the following Table II:

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Table II
LFCR Flat Charge Rates

Total Monthly Metered kWh	LFCR Flat Charge Rate (Per No. of Days in Billing Cycle)
0-400 kWh	$ 0.020
401-800 kWh	$ 0.040
801-2000 kWh	$ 0.092
2001 kWh and greater	$ 0.217

59. The following Table III illustrates the difference between the LFCR percent of bill charge and the LFCR Flat Charge for a typical APS customer. In this example, Staff assumes the customer consumes 1,600 kWh during summer months and 900 kWh during winter months, or 14,200 kWh annually. This customer's average monthly consumption would therefore be 1,192 kWh. The LFCR percent of bill charge is currently assessed at the rate of 0.2 percent of the customer's monthly bill. For simplicity, the customer's monthly bill is presented before on-site generation is netted from the bill. The LFCR Flat Charge is assessed at the tiered rates presented above in Table II times the number of billing days in the month. For purposes of this example, a 30-day billing month is assumed.

Table III
LFCR Monthly Charge Comparison

Rate Design Type	Average Monthly Bill	Average Monthly LFCR Percent of Bill	Average Monthly LFCR Flat Charge
IB - Inclining Block	$195.57 before solar $61.65 after solar	$0.39 $0.12	$2.76 $2.76
TOU - Time of Use Energy	$169.88 before solar $56.34 after solar	$0.34 $0.11	$2.76 $2.76

60. Staff proposes that the LFCR Flat Charge provision become mandatory for all new APS DG customers, unless the customer chooses the ECT-2 rate. New DG customers would pay into the LFCR account at the flat rates set in the LFCR, thereby reducing the aggregate LFCR account needing to be repaid by non-DG customers. In this way, the LFCR Flat Charge provision

provides a revenue-neutral method of shifting a portion of the NM-shifted costs back to the customer with newly-installed DG, and away from the non-DG customer.

61. Staff believes that the LFCR adjustor mechanism is an appropriate near-term bridge solution to APS's NM cost-shift issue as this adjustor was specifically designed to address lost fixed costs. Staff notes that LFCR mechanisms have been approved by the Commission in several recent electric and gas utility rate cases[8]. In addition, APS's LFCR mechanism was constructed with a certain amount of flexibility that accommodates this proposal.

62. Staff has calculated the customer bill impact for Staff's Recommended Alternative #1 for a hypothetical APS customer with DG and without DG and these results are presented below in Table IV. For purposes of this example, Staff has utilized a customer consumption profile depicting a summer consumption of 1,600 kWh / month and a winter consumption of 900 kWh / month.

Table IV
Estimated Bill Impacts from Staff's Recommended Alternative #1

	Current NM Program			**Staff Option 1 -LFCR Flat Charge Rate**		
IB Rate	Summer	Winter	Annual	Summer	Winter	Annual
Bill before solar (w/tax)	$275.22	$115.91	$195.57	$275.22	$115.91	$195.57
Bill with solar	$92.64	$30.65	$61.65	$95.47	$31.90	$63.69
Savings	$182.58	$85.26	$133.92	$179.75	$84.01	$131.88
% savings	66.3%	73.6%	68.5%	65.3%	72.5%	67.4%
TOU E Rate	Summer	Winter	Annual	Summer	Winter	Annual
Bill before solar (w/tax)	$224.63	$115.13	$169.88	$224.63	$115.13	$169.88
Bill with solar	$72.19	$40.48	$56.34	$75.07	$41.72	$58.40
Savings	$152.44	$74.65	$113.55	$149.56	$73.41	$111.49
% savings	67.9%	64.8%	66.8%	66.6%	63.8%	65.6%

[8] LFCR mechanisms have recently been approved by the Commission in these general rate cases: Tucson Electric Power Company, Decision No.73912 (2013); APS, Decision No. 73732 (2012); and UNS Gas, Decision No. 73142 (2012). In addition, an LFCR mechanism is proposed in UNS Electric's Settlement Agreement, Docket No. E-04204A-12-0504.

Staff Recommended Alternative #2
LFCR DG Premium for All New DG Customers

63. As noted above, the various stakeholders that participated in the Technical Conference had vastly differing estimates regarding the *value* of DG solar. In response to the Crossborder Study's estimated value of 22 to 24 cent per kWh for DG solar, APS made the following argument: Assuming, *arguendo*, that DG solar creates the value estimated in the Crossborder Study, APS can replicate that value by interconnecting small 1 to 5 MW PV systems at the subtransmission level throughout its distribution system utilizing wholesale purchase power agreements ("PPA") at a significantly lower cost than acquiring the same amount of solar capacity via DG.

64. Utilizing APS's rationale of acquiring the most value at the lowest cost, Staff's second recommended alternative would establish a cap on the NM incentive to ensure that it is no greater than the price APS would pay to acquire the same amount of solar via a wholesale PPA. This would ensure that APS's non-DG customers attain the value of solar, at the lowest cost. The LFCR DG Premium would be based on the difference between APS's cost for purchasing a DG customer's excess generation, and its cost to purchase an equivalent amount of energy from a wholesale PPA. The calculated difference would, in effect, establish the "DG Premium."

65. The following example illustrates Staff's calculation of the DG Premium and resultant charge for a hypothetical APS residential DG customer:

A. Customer DG System Size:	6.4 kW
B. Assumed Annual Rate of Production:	1,641 kWh / kW
C. Calculated Annual Production:	10,502 kWh (A x B)
D. Assumed Customer Retail Rate:	$0.125/kWh
E. Annual Retail Cost of Production:	$1,312.75 (C x D)
F. Assumed Utility Scale PPA Rate:	$0.10/kWh
G. Annual PPA Cost of Production:	$1,050.20 (C x F)
H. Annual DG Premium:	$262.55 (E – G)
I. Monthly DG Premium:	$21.88 (H/12)
J. LFCR DG Premium per kW:	$3.42 (I/A)

66. Staff understands that utility scale solar PV generation can be obtained in Arizona for between 7 and 10 cents per kWh under a PPA arrangement. Staff has picked conservative

values for the Assumed Retail Rate and the Assumed Utility Scale PPA Rate in the example presented above. See Appendix III for examples of the DG Premium calculated using a range of values for the retail rate and PPA rates. In the above example (6.4 kW DG system size), Staff calculates the proposed DG Premium as $3.42 / kW.

67. If the Commission chooses, it could implement the DG Premium on a gradual basis so as to minimize the immediate impact on future DG customers. This could be done by initially setting the DG Premium at $2.75 / kW. The DG Premium calculated in the above example would be the cap for the monthly charge under this Alternative. The Commission may wish to lower or increase the DG Premium annually based on the effect it has on new DG installations. The Commission may also wish to adopt an approach wherein the DG Premium is initially set at a lower amount than that recommended by Staff, and phase-in the total DG Premium over a period of years.

68. Staff has calculated the DG Premium for a range of DG system sizes, and this information is presented in the following Table V:

Table V
Monthly DG Premium By DG System Size

A. Customer DG System Size (kW)	4	6.4	8	10	12
B. Assumed Annual Rate of Production (kWh)	1641	1641	1641	1641	1641
C. Calculated Annual Production (kWh)	6,564	10,502.40	13,128	16,410	19,692
D. Assumed Customer Retail Rate ($/kWh)	$ 0.125	$ 0.125	$ 0.125	$ 0.125	$ 0.125
E. Annual Retail Cost of Production	$ 820.50	$ 1,312.80	$ 1,641.00	$ 2,051.25	$ 2,461.50
F. Assumed Utility Scale PPA Rate ($/kWh)	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ 0.10
G. Annual PPA Cost of Production	$ 656.40	$ 1,050.24	$ 1,312.80	$ 1,641.00	$ 1,969.20
H. Annual DG Premium	$ 164.10	$ 262.56	$ 328.20	$ 410.25	$ 492.30
I. Monthly DG Premium	$ 13.68	$ 21.88	$ 27.35	$ 34.19	$ 41.03

69. Staff proposes that the LFCR DG Premium be collected through the LFCR. Relatively minor modifications would be required to the LFCR Plan of Administration to implement collection of the DG Premium.

. . .

70. New DG customers would pay into the LFCR account at the DG Premium established by the Commission, thereby reducing the aggregate LFCR account needing to be repaid by non-DG customers. In this way, the LFCR DG Premium provision provides a revenue-neutral method of shifting a portion of the NM shifted costs back to the customer with newly-installed DG, and away from the non-DG customer.

71. Staff has calculated the customer bill impact for Staff's Recommended Alternative #2 for an APS customer with DG (6.4 kW DG system size and estimated consumption of 1,600 kWh/month in Summer and 900 kWh / month in Winter) and without DG and these results are presented below in Table VI.

Table VI
Estimated Bill Impacts from Staff's Recommended Alternative #2

	Current NM Program			Staff Option 2 -Standby Cap. Charge		
IB Rate	Summer	Winter	Annual	Summer	Winter	Annual
Bill before solar (w/tax)	$275.22	$115.91	$195.57	$275.22	$115.91	$195.57
Bill with solar	$92.64	$30.65	$61.65	$108.64	$46.65	$77.65
Savings	$182.58	$85.26	$133.92	$166.58	$69.26	$117.92
% savings	66.3%	73.6%	68.5%	60.5%	59.8%	60.3%
TOU E Rate	Summer	Winter	Annual	Summer	Winter	Annual
Bill before solar (w/tax)	$224.63	$115.13	$169.88	$224.63	$115.13	$169.88
Bill with solar	$72.19	$40.48	$56.34	$88.19	$56.48	$72.34
Savings	$152.44	$74.65	$113.55	$136.44	$58.65	$97.55
% savings	67.9%	64.8%	66.8%	60.7%	50.9%	57.4%

72. Staff believes that any DG customers that are presently taking service under the ECT-2 rate should be allowed to remain on the ECT-2 rate and be exempt from either of Staff's Recommended Alternatives, should they decide to install a DG system prior to APS's next general rate case.

Grandfathering

73. If the Commission chooses either Staff Alternative #1 or Staff Alternative #2 (or any form of either), Staff recommends that any residential customers who either have a DG system installed on their homes now, or who submit an application and a signed contract with a solar installer to APS by December 31, 2013, be grandfathered under the current NM policies. Staff

further recommends that any consideration of grandfathering existing NM situations should view the grandfathering as pertaining to the DG system and premises where the DG system is sited (in other words "runs with the land"), versus a "right" that resides with a specific customer.

74. Staff believes that it is important to clarify its position on grandfathering so that all parties are clear as to the Order's intent. Staff has recommended that all residential customers who either have a DG system installed on their homes or who submit an application and a signed contract with a solar installer to APS by December 31, 2013, should be grandfathered ("Existing DG Customers").

75. Staff qualifies the use of the term "grandfather" in the following manner. First, it is unrealistic to view any rate structure as permanent, thereby purporting to bind future Commissions. Any adjustment adopted today is a bridge proposal, and the Commission's review of this matter in APS's next rate case could lead to higher or lower rates or a completely different rate structure for its customers, including DG customers. If DG customers' rates were frozen, they would not be able to receive benefits (if any) of future changes or rate structures. Therefore, Staff clarifies that its use of the term "grandfather" means that the status quo for existing DG customers should be preserved until such time as the Commission considers this issue in APS's next rate case or in other future orders of the Commission.

<u>Staff's Proposed Consumer Protection Advisory</u>

76. Regardless of which option the Commission chooses, Staff recommends that APS be directed to separate and isolate on a separate page of the Interconnection Agreement[9] the existing language found on Page 9, Paragraph 10.6, of said agreement, plus the additional language, as shown in Appendix IIA.

77. Staff makes this recommendation in an attempt to ensure that customers purchasing and installing PV systems on their premises are fully aware that current rates applying to their PV system are not permanent. If the Commission believes the language contained in Appendix IIA is too onerous in tone, Staff recommends the language in Appendix IIB.

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[9] See APS's Interconnection Agreement posted at http://www.aps.com/library/solar%20renewables/ResInterconnAgreeSample.pdf)

78. We agree with Staff that there should be a separate disclaimer, but find that the disclaimer language proposed by Staff in Appendix IIA should be modified as set forth below. APS shall require the residential customer owning or leasing the interconnecting rooftop solar system to sign the following "Disclaimer" as part of the interconnection process:

DISCLAIMER

POSSIBLE FUTURE RULES and/or RATE CHANGES AFFECTING YOUR ROOFTOP PHOTOVOLTAIC SYSTEM

The following is a supplement to Paragraph 10.6 of the Interconnection Agreement you signed with the Arizona Public Service Company ("APS").

1. *APS electricity rates, basic charges and service fees are subject to change. Future adjustments to these items may positively or negatively impact any potential savings or the value of your rooftop photovoltaic system.*

2. *You will be responsible for paying any future increases to electricity rates, basic charges or service fees from APS.*

3. *Your rooftop photovoltaic system is subject to the current rates, rules and regulations established by the Arizona Corporation Commission ("Commission"). The Commission may alter its rules and regulation and/or change rates in the future, and if this occurs, your system is subject to those changes.*

4. *Any future electricity rate projections presented to you are not approved by APS or the Commission. They are based on projections formulated by external third parties not affiliated with APS or the Commission.*

By signing below, you acknowledge that you have read and understand the above disclaimer.

____
Name

____
Date

...

...

...

The Commission's Balancing in the Public Interest to Address the Cost Shift Issue on an Interim Basis Until the Next APS Rate Case Decision.

79. There are a wide range of proposals in the docket for the Commission to consider in this matter, and the Commission appreciates the public comment and stakeholders' filings on these important issues.

80. In balancing the various positions expressed in the docket, the Commission finds that it is in the public interest to approve an interim LFCR DG adjustment that will be accounted for through APS's LFCR mechanism to address the cost shift from APS's residential DG customers to APS's residential non DG customers resulting from the proliferation of solar installations on residential rooftops. The approval of an interim LFCR DG adjustment through a modification to APS's LFCR mechanism will address the cost shift in a revenue neutral manner by reducing the amount of lost fixed costs APS must collect from residential non DG customers.

81. The interim LFCR DG adjustment shall apply only to new residential DG customers on or after January 1, 2014, and will be in effect until the Commission's decision in APS's next full rate case unless otherwise ordered by the Commission. The interim LFCR DG adjustment shall not apply to any customer on APS's ECT-2 rate.

82. In determining the appropriate interim LFCR DG adjustment, we find aspects of both Staff's Alternative 2 and RUCO's recent proposal to be especially helpful for the Commission's weighing in the public interest of the various views expressed in the docket.

83. Staff and RUCO have reached similar conclusions as to appropriate LFCR DG adjustments to address the cost shift issue based upon different methods of calculation.

84. We find that among the range of Staff's and RUCO's LFCR DG adjustments' proposals, a $3.00 per kW per month (which would be $ 21.00 for a customer system of 7kW) is reasonable for new DG customers.

85. However, under the circumstances presented in this docket, we find, as suggested by RUCO, it appropriate to institute a fixed charge using the LFCR DG adjustment for new DG customers who signed a contract with a solar installer after December 31, 2013, by implementing the adjustment at $.70 per kW per month, an amount that will be easy to use and understand by

customers. The Commission may periodically adjust this charge in any APS LFCR reset proceeding.

86. For customers who sign a contract with an installer and become subject to the $.70 per kW charge, the amount of this charge shall be grandfathered until the next rate case. In the next rate case, this charge may be increased, decreased, left as is, or eliminated.

87. If the Commission subsequently adjusts the LFCR DG adjustment, the new adjustment shall only apply to new DG customers who sign a contract with a solar installer after the LFCR DG adjustment is adopted.

88. These successive tranches shall remain in place until APS's next rate case.

89. We shall require APS to report quarterly on its compliance with the REST Rules in light of the interim LFCR DG adjustment, and the impact of the $.70 per kW per month on APS's compliance. At a minimum, the report shall include the number of DG installations per month, size of the installations by kW, and the amount collected each month through the interim LFCR DG adjustment. These reports shall be filed by each April 15th, July 15th, October 15th, and January 15th and cover the previous 3 month period; with the first report due April 15, 2014. A solar customer who fails to register its system with APS will result in a $3 per kW charge. Residential customers who either have a DG system installed on their homes now, or who submit an application and a signed contract with a solar installer to APS by December 31, 2013, shall have their system grandfathered under the current net metering policies until the next rate case, and such policies shall be deemed to run with the premises and the system.

90. We find that approving an interim LFCR DG adjustment as discussed herein through a modification to APS's LFCR mechanism is just and reasonable for APS and its customers. The Commission also acknowledges that ratepayers who want to install solar rooftop panels need certainty. The Commission, however, cannot bind future Commissions with regard to rates. Thus, it is the policy of this Commission to provide as much regulatory certainty to non-solar and solar customers alike as possible.

91. In APS's last rate case, the parties to the settlement agreement concluded that the proliferation of DG will lead to lost fixed costs:

> *The signatories . . . recognize that, under APS's current volumetric rate design, the Company recovers a significant portion of its fixed costs of service through kilowatt-hour ("kWh") sales. Commission rules related to EE and Distributed Generation ("DG") require APS to sell fewer kWh, which, in turn, prevents the Company from being able to recover a portion of the fixed costs of service embedded in its energy rates.*

Decision No. 73183, Exhibit A, ¶ 9.1.

92. They also proposed a Lost Fixed Cost Recovery ("LFCR") mechanism as a means of allowing APS to recover its lost fixed costs:

> *[T]he signatories intend that a Lost Fixed Cost Recovery ("LFCR") mechanism with residential opt-out rates shall be adopted that allows APS relief from the financial impact of verified lost kWh sales attributable to Commission requirements regarding EE and DG while preserving maximum flexibility for the Commission to adjust EE and DG requirements, either upward or downward, as the Commission may deem appropriate as a matter of policy. Nothing in this Agreement is intended to bind the Commission to any specific EE or DG policy or standard.*

Decision No. 73183, Exhibit A, ¶ 9.2.

93. In Decision No. 73183, we adopted the settlement agreement proposed by the parties, and we specifically agreed with the provisions set forth above.

94. Decision 73183 (and the Plan of Administration for the LFCR approved therein) set forth a specific method for calculating the yearly dollar amounts to be recovered by the LFCR (hereinafter referred to as "annual LFCR revenue").

95. From our review of the record before us, it is apparent that DG customers are allocated cost responsibility for a disproportionately smaller share of the annual LFCR revenue than non-DG customers. In other words, DG customers contribute less to APS's recovery of its annual LFCR revenue than do non-DG customers, even though DG customers are responsible for creating more lost fixed costs than non-DG customers.

96. The result is inequitable: it is simply unfair for DG customers to contribute less to the recovery of APS's annual LFCR revenue than non-DG customers do. A basic principle of revenue allocation across customer classes is that the cost causer should bear a fair share of the costs that he creates. A revenue allocation that achieves the opposite result can only be regarded as defective.

97. We therefore conclude that the current revenue allocation method (as between DG customers and non-DG customers, respectively) for the recovery of APS's annual LFCR revenue is defective.

98. Some parties to this case contend that we are constrained in our ability to address any potential defects in APS's LFCR unless we undertake a full rate case. Specifically, they argue that *Scates v. Ariz. Corp. Comm'n,* 118 Ariz. 531, 578 P.2d 612 (App. 1978), prevents any changes to APS's rates without a full rate case. They also argue that the stay-out provision of our order in APS's last rate case (Decision No. 73183) precludes any changes in APS's rates before July 1, 2016.

99. In order to maximize the information before us, Staff recommends that we defer these issues until APS's next rate case. Although we would prefer to wait until a rate case to address these issues, the delay inherent in such an approach would not serve the public interest.

100. We take this opportunity to acknowledge the significant volume of attention that this case has received. The Commission has received not only numerous filings from the parties to the case, but also an unusually high number of public comments, whether by mail, e-mail, or telephone. This case has also been the subject of significant media coverage. Clearly, the degree of attention that this case has attracted is an indication of the importance of addressing these issues in a timely manner.

101. Under the circumstances of this case, we conclude that *Scates* does not preclude the remedy that we adopt herein. *Scates* does not require a full rate case every time the Commission changes rates; instead, it merely requires the Commission to ascertain the utility's fair value and to consider the impact of any rate increase upon the utility's rate of return.

102. In this case, we are not increasing APS's revenues in any way; instead, we are merely adjusting the allocation of cost responsibility (as between DG and non-DG customers) for APS's annual LFCR revenue. For the purposes of this case, we find that APS's fair value rate base is $8,167,126,000, the number that we approved in APS's last rate case (Decision No. 73183). We also find that 6.09 percent (APS's current fair value rate of return) remains appropriate as a fair

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value rate of return. These findings are appropriate because we are not increasing APS's revenue requirement.

103. A full rate case for a utility of APS's size can be time-consuming. To read *Scates* as requiring a full rate case in order to address the defect identified herein would be harmful to the public interest, especially in light of our express consideration of the fair value information and the fair value rate of return information addressed in these Findings of Fact.

104. The adjustments adopted herein are intended to be revenue neutral to APS. To ensure a revenue neutral result, we will make these adjustments interim and subject to true-up in APS's next rate case, which we will require APS to file at the earliest date consistent with our order in Decision No. 73183.

105. We also conclude that the rate case stay-out provision in Decision No. 73183 does not prevent us from adopting appropriate changes in the LFCR. Although we recognize that the parties to Decision No. 73183 contemplated that APS would not file its next general rate case before June 1, 2015, we note that the settlement agreement (in paragraph 19.1) also stated that "[n]othing in this provision is intended to limit the Commission's authority to change rates at any time pursuant to its lawful authority." That paragraph also recognizes that the Commission retains the ability to respond to an extraordinary event that requires rate relief in order to protect the public interest.

106. We find that the presence of a defect in the method for allocating the revenue spread in the LFCR is such an "extraordinary event," and we believe that it is in the public interest for us to address it now. To conclude that our decision in APS's last rate case (Decision No. 73183) forecloses interim action would be unreasonable, especially in light of paragraph 19.1.

107. We further recognize that our changes herein have been limited to the LFCR. Paragraph 9.11 of the settlement agreement provides that "*[t]he LFCR shall be subject to Commission review at any time* . . . ." In paragraph 9.13, the agreement provides that the LFCR is "*designed to be a flexible means to maximize the policy options available to the Commission and to customers, allowing the pursuit of . . . DG programs at any level or pace directed by the Commission.*" Our order in Decision No. 73183 adopted the LFCR as proposed, and our adoption

thereof was based on our understanding that the LFCR is an adjustor mechanism, subject to adjustments and mid-course corrections between rate cases. Our adjustments as adopted herein fall within the type of adjustments contemplated by Decision No. 73183 and the settlement agreement in that proceeding.

108. APS's proposals in this case, while arguably related to rate design, carry with them the potential to change APS's rates in a way that is not revenue neutral. We therefore expressly reject these proposals at this time.

CONCLUSIONS OF LAW

1. Arizona Public Service Company is an Arizona public service corporation within the meaning of Article XV, Section 2, of the Arizona constitution.

2. The Commission has jurisdiction over Arizona Public Service Company and over the subject matter of the application.

3. The Commission, having reviewed Arizona Public Service Company's application and Staff's Memorandum dated September 30, 2013, concludes that addressing the net metering cost-shift issue would benefit from a detailed analyses of the costs and benefits of distributed generation systems, and therefore, it is in the public interest to consider these matters further in Arizona Public Service Company's next general rate case.

4. In the period between the effective date of this order and the Commission's decision in APS's next rate case, it is also in the public interest to address in this docket the cost shift by approving an interim LFCR DG adjustment through a revenue neutral modification of APS's LFCR mechanism to ameliorate the impact of the cost shift on residential non DG customers. Staff's alternative 2, as modified herein, is an appropriate interim adjustment.

5. For the purpose of this case, we will rely on the fair value rate base and fair value rate of return findings that we adopted in APS's last rate case. These findings are appropriate because we are not increasing APS's revenue requirements.

6. The Court of Appeals' opinion in *Scates* does not preclude the remedy that we adopt herein.

. . .

7. Our order in APS's last rate case (Decision No. 73183) does not preclude us from adopting appropriate changes to the LFCR.

8. The presence of a defect in the method for allocating the revenue spread in the LFCR is an "extraordinary event" for purposes for Decision No. 73183.

9. The changes that we adopt herein are limited to the LFCR mechanism.

10. The adjustments adopted herein are interim and are subject to true-up in APS's next rate case.

ORDER

IT IS THEREFORE ORDERED that Arizona Public Service Company shall implement a $.70 per kW per month interim LFCR DG adjustment for all residential DG installations after December 31, 2013, consistent with the Commission's findings herein. The interim LFCR DG adjustment shall not apply to any customer on Arizona Public Service Company's ECT-2 rate.

IT IS FURTHER ORDERED that Arizona Public Service Company shall file by December 6, 2013, as a compliance item in this docket, its proposed modifications to its Plan of Administration for its LFCR mechanism to incorporate the interim LFCR DG adjustment approved in this decision, for Staff approval.

IT IS FURTHER ORDERED that Arizona Public Service Company shall file quarterly reports as discussed herein, with the first report due April 15, 2014. At a minimum, the report shall include the number of DG installations per month, size of the installations by kW, and the amount collected each month through the interim LFCR DG adjustment.

IT IS FURTHER ORDERED that the LFCR DG adjustments approved herein shall not apply to residential DG customers who already have their DG system installed or who submit an application and a signed contract with a solar installer to APS by December 31, 2013. These customers shall be grandfathered under the "Grandfathering" section of this decision.

IT IS FURTHER ORDERED that customers who sign a contract with an installer after December 31, 2013 and become subject to the $.70 per kW charge, shall be grandfathered at the $.70 per kW charge until APS's next rate case. In the next rate case, the $.70 per kW charge may be increased, decreased, left as is or eliminated.

IT IS FURTHER ORDERED that if the Commission subsequently modifies the LFCR DG adjustment before APS's next rate case, the new adjustment shall only apply to new DG customers who sign a contract with a solar installer after the modified LFCR DG adjustment is adopted by the Commission. This tranch of customers and any successive tranches of customers shall remain in place until APS's next rate case decision.

IT IS FURTHER ORDERED that APS shall file its next general rate case in June 2015, consistent with the provisions of Decision No. 73183.

IT IS FURTHER ORDERED that the Commission will open a generic docket on the net metering issue and hold workshops with all stakeholders to help inform future Commission policy on the value that DG installations bring to the grid.

IT IS FURTHER ORDERED that the workshops shall investigate the currently non-monetized benefits of DG with the goal of developing a methodology for assigning DG values, because the NM cost-shift issue will be faced by all Arizona electric utilities as the penetration level of DG increases in each of the companies' individual service territories. The workshops shall be based upon the Commission's determination of the presence of a cost shift from DG customers to non DG residential customers, and shall provide for the Commission's future full consideration of the net metering cost shift issue, the development of a method(s) by which the value of DG can be considered in balancing the public interest, and the evaluation of the role and value of the electric grid as it relates to rooftop solar, other forms of distributed generation, and customer-sited technology generally. In a future Commission/Staff Open Meeting the Commission may give Staff further direction on the content and process of the workshops.

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IT IS FURTHER ORDERED that no later than November 18, 2013, Arizona Public Service Company shall separate and isolate on a separate page of its Interconnection Agreement the existing language found on Page 9, Paragraph 10.6, of said agreement, plus the additional language in the disclaimer form described herein. APS shall require each residential customer owning or leasing an interconnecting rooftop solar system to sign the "Disclaimer" as part of the initiation of the interconnection process.

IT IS FURTHER ORDERED that this Order shall become effective immediately.

BY THE ORDER OF THE ARIZONA CORPORATION COMMISSION

CHAIRMAN COMMISSIONER

COMMISSIONER COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, JODI JERICH, Executive Director of the Arizona Corporation Commission, have hereunto, set my hand and caused the official seal of this Commission to be affixed at the Capitol, in the City of Phoenix, this 3rd day of December, 2013.

JODI JERICH
EXECUTIVE DIRECTOR

DISSENT:

DISSENT:

SMO:RLB:lhm\MAS

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DOCKET NO. E-01345A-13-0248

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ARIZONA CORPORATION COMMISSION

November 21, 2013

Re: Commissioner Gary Pierce's Dissent to the decision adopted by the Commission at its November 14, 2013 Open Meeting concerning Arizona Public Service Company's Application for Approval of Net Metering Cost Shift Solution (Docket No. E-01345A-13-0248).

In its decision, the Commission adopted what in my view, is a new policy on Net Metering. The new policy was a compromise proposal by representatives of the solar industry and the Residential Utility Consumers Office (RUCO). The new policy would add less than $5.00 per month to the bill of the average new solar customer, where I believe the data submitted indicates that the actual cost shift is closer to $50.00 per month. If this is accurate, this means that less than 10% of the cost shift problem is being addressed.

I voted "no" on this new policy for a number of reasons.

Although the new policy recognizes the existence of a cost shift from solar residential Distributed Generation (DG) customers to non-solar residential DG customers, it does very little to correct the problem. In effect, the Commission's decision has "kicked the can down the road", instead of addressing the cost shift issue in a meaningful manner when it had the opportunity. Because of the increase in the number of APS's residential customers choosing to install solar systems on their roof tops, these cost shift inequities will only continue to get worse. Thus, it will become more and more difficult for a future Commission to appropriately allocate the costs to the cost causers. As it has been said, "if you rob Peter to pay Paul, you will always have the support of Paul."

If future Commissions do not fairly allocate costs to the cost- causers related to this cost shift, it is very likely that the cost burden will have to be borne by APS's other residential non DG customers. This result would raise rates to all customers, and serve as a "feed-in tariff" for solar energy. If that is what the present Commission wants, we should be transparent about it and call it what it is, with a line item for it on all ratepayer's monthly bills.

I am also concerned that we have seen that all sides of this matter are not afraid to spend significant amounts to campaign for support for their special interests. The independence of the Commission to do its work on behalf of the citizens of Arizona may come into question, unless the Commission resists the pressure presented by these special interest campaigns. It is my great hope that the Commission that will need to deal with this in the future, will resist the pressure brought upon them by special interests, and do what is right and fair for ratepayers.

Comments provided to the docket and Staff did a great job in providing us with the information that we needed. We had a unique opportunity to set a national policy precedent and I believe that we failed to grasp that opportunity. I believe we failed to protect the 98% of APS's ratepayers that do not have solar.

Gary L. Pierce

Gary Pierce
Commissioner

Decision No. 74202

COMMISSIONERS
BOB STUMP - Chairman
GARY PIERCE
BRENDA BURNS
BOB BURNS
SUSAN BITTER SMITH

ARIZONA CORPORATION COMMISSION

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December 3, 2013

RE: Arizona Public Service (Net Metering); Docket No. E-01345A-13-0248

DISSENT BY COMMISSIONER BRENDA BURNS

Solar rooftop development has been a positive in many ways for Arizona. We are known around the country as the "solar state" denoting a promise of an exciting technology that can be environmentally friendly and be a new source of electrical generation. As for the grid, we are on the precipice of history. Energy storage, Bloom Boxes, The Cube and other recent innovations are harbingers of what is to come in the 21st Century. But, how do we handle disruptive technologies while embracing and addressing a new paradigm? We do so by being mindful of shifting costs and by addressing changes to our model.

I agree with those who say we need a broader and more in-depth discussion on use of the grid and what constitutes a 'fair share'. In this case, however, the core of the Net Metering issue often got lost in the politicized discussion. The root of the issue is how to determine the 'fair price' that APS pays for the excess solar distributed generation which it is mandated to purchase from residential customers. That price is ultimately passed on to the other (non-solar) ratepayers.

Staff Alternative #2 calculated that 'fair price' as the cost of the least expensive way to obtain all the benefits that rooftop solar provides, which would translate to $21.88 per month for a typical 6.4kW system. One could easily argue that the fair price should be determined by a comparison to the least expensive energy source available, not just solar. However, in view of our Renewable Energy Standard, Staff's method has merit.

RUCO's calculation of the short-term cost shift ranged up to $50 per month, per customer, which was close to APS's. However, RUCO's long-term 'cost shift' number at $21 per month aligned closely with Staff Alternative #2's proposed solution of $21.88 per month for a 6.4kW system. Additionally, given that RUCO's hired consultant on Net Metering represented rooftop solar interests immediately prior to his work for RUCO, I put a great deal of weight in his cost-shift calculation and my proposed amendment was an attempt at an equitable solution. I was struck by the notion that even a prominent rooftop solar advocate conceded there was a sizable cost shift.

In addition, this Decision is based on the assertion that solar customers are only saving $5 to $10 per month. This Commission should not have used just one solar company's business model as the basis for the whole debate. For example, at the Commission's Public Comment, one ratepayer stated that he saves about $17 per month due to his leased rooftop solar installation. Also, a letter from a couple who own their rooftop solar suggested that any new fee should not be greater than $15-$25 month, which indicates their own savings are considerably more than $5-$10.

Four Commissioners, including myself, found a 'cost shift' of at least $3 per kW per month. The Decision to implement a charge of $0.70 per kW per month is far below that amount.

Therefore, the balance of the $21 'cost' (per RUCO's long-term analysis) leaves more than 75%, about $16.10 per month for a typical 7kW system, to be paid by all other ratepayers. The balance of the $50 'cost' (per RUCO's short-term analysis) leaves 90%, about $45.10 month for a typical 7kW system, to be paid by all other ratepayers. (*See attachment)

The cost shift created by net metering is in addition to the $170 million of Up-Front Incentives (UFIs) which APS ratepayers have already paid, and the $700 million in Performance Based incentives (PBIs) which they will be paying over the next 20 years. Additionally, all five commissioners supported the proposal to grant a so-called "grandfathering" status for the existing 18,000 rooftop solar systems. The 'cost shift' of those 18,000 systems, if we utilize RUCO's $21 short-term analysis, is $4.5 million per year, and if we utilize RUCO's $50-short term analysis is $10.8 million per year. These costs will also be picked up by non-solar ratepayers.

I am always mindful of drawing a distinction when talking about a 'ratepayer' and a 'taxpayer'. Some tax laws are written at the legislature that pursue economic development and reflect public policy. However, my role as a regulator is to set fair rates, not tax policy.

In this instance, a 'choice' for one ratepayer will ultimately be a monthly bill increase for another ratepayer. There are at least 18,000 solar installations today and we applaud the early adopters. But, how many more ratepayers will install solar between now and the next rate case and how do we continue to tell the other non-solar ratepayers to make up the difference?

The solar industry hails their product as a "free market choice". While 'choice' is optimal in a free market there is nothing "market-driven" about the way we do Net Metering. Forcing the utility to buy excess distributed generation at the retail rate is not a competitive way of doing business. The other ratepayers act as guaranteed buyers who have to pay the bill.

All Commissioners have acknowledged that a cost shift to other ratepayers exists. Ignoring the problem or understating the impact, will not make it go away. The magnitude of the problem will continue to accumulate on a daily basis and one day in the future we will ask ourselves, 'how did we get to this point?' If so, many will point to what happened here. Unfortunately, this Decision does too little to keep from exacerbating an existing problem. Therefore, I must dissent.

Brenda Burns

Brenda Burns
Commissioner

*Please see attachment

If Cost Shift is $50 per month					
7kW system*					
	Monthly	%	1 system, 1 year	5714 systems per year	20 years
Solar Customers	$4.90	9.8%	$58.80	$335,983.20	$6,719,664.00
Non-Solar (Other) Ratepayers	$45.10	90.2%	$541.20	$3,092,416.80	$61,848,336.00
Total	$50.00		$600.00	$3,428,400.00	$68,568,000.00

If Cost Shift is $21 per month					
7kW system*					
	Monthly	%	1 system, 1 year	5714 systems per year	20 years
Solar Customers	$4.90	23.3%	$58.80	$335,983.20	$6,719,664.00
Non-Solar (Other) Ratepayers	$16.10	76.7%	$193.20	$1,103,944.80	$22,078,896.00
Total	$21.00		$252.00	$1,439,928.00	$28,798,560.00

***Using RUCO's analysis**