ORIGINAL

OPEN MEETING

MEMORANDUM

TO: THE COMMISSION

FROM: Utilities Division

DATE: September 30, 2013

RE: ARIZONA PUBLIC SERVICE COMPANY – APPLICATION FOR APPROVAL OF NET METERING COST SHIFT SOLUTION (DOCKET NO. E-01345A-13-0248)

On July 12, 2013, Arizona Public Service Company ("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 intervenor 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").

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

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.

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

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.

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.

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."

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

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.

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.

---

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

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 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.

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. 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.

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").

1. <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.

2. <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.

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

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.

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.

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.

1. Select either the NM Option or the Bill Credit Option;

2. Grandfather the rates and use of NM by existing and immediately pending DE customers;

3. 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;

4. Address this matter on an expedited basis; and

5. Grant any waivers or other forms of relief that the Commission deems appropriate.

Staff Analysis

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.

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).

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 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.

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

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. 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.

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.

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.

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

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.

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."

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.

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

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.

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

---

[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 May 8, 2013, and filed in this docket on July 2, 2013.
[6] Rocky Mountain Institute, *A Review of Solar PV Benefit & Cost Studies*, undated.

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

ETC-2 Plus NM Option

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 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.

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 Option

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.

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.

[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."

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.

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	$ 152.44	$ 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%

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.

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.

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

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.

Stakeholder Proposals

Three alternative cost-shift solution proposals have been received from intervenors 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.

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.

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.

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.

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.

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.

The NM Cost-Shift Issue in Other Jurisdictions

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 this Memorandum.

Staff Recommendations

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.

Staff's Recommendation

Address in Next Rate Case

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.

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 company's 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.

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.

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 the lost fixed costs are recovered from through the LFCR. Consequently, Staff's two alternative recommendations are also revenue neutral.

Staff Recommended Alternative #1
LFCR Flat Charge for All New DG Customers

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.

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:

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

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

Staff proposes that the LFCR Flat Charge provision become mandatory for all new APS DG customers, unless the customer chooses the ETC-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.

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.

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.

[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.

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%

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

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.

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."

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)

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.

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.

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

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.

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.

Staff has calculated the customer bill impact for Staff's Recommended Alternative #2 for 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%

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

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 October 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.

Staff's Proposed Consumer Protection Advisory

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 Staff's additional language, as shown in Appendix IIA.

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.

Steven M. Olea
Director
Utilities Division

SMO:RBL:sms\MAS

ORIGINATOR: Rick Lloyd

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

APPENDIX I

California

The California State Legislature passed Assembly Bill 2514[10] in September 2012 that directed the California Public Utilities Commission ("CPUC") to complete a study analyzing the full costs and benefits of the state's NM program. The bill further requires the CPUC to determine the extent to which NM customers pay for the full costs of electric services provided by the utilities. Specifically, the bill requires a study "...to determine who benefits from, and who bears the economic burden, if any, of the net energy metering program, and to determine the extent to which each class of ratepayers and each region of the state receiving service under the net energy metering program is paying the full cost of the services provided to them by electrical corporations, and the extent to which those customers pay their share of the costs of public purpose programs." The CPUC is required to complete the report by October 1, 2013, and deliver the results of the report to the Legislature within 30 days of its completion.

A second California State Legislature bill, AB 327, was recently passed by the state Assembly and forwarded to the California Governor for signature. This bill addresses residential electric rate reforms and provides a vehicle for extending the state's solar NM program, which otherwise faced expiration in 2014. The bill sets up a specific process for developing a new state-wide NM program. In addition, the bill authorizes the CPUC to: (1) lower the ramp on California's tiered energy rates; (2) increase monthly customer charges by up to $10 per month; and (3) clarifies the methodology of calculating each utility company's NM capacity cap.

Idaho

On November 30, 2012, Idaho Power Company ("IPC") applied to the Idaho Public Utilities Commission ("IPUC") to modify its NM service. IPC's application requested that IPUC approve four changes to IPC's NM service:

1. Increasing the NM capacity cap. IPC requested that the ceiling for the amount of NM capacity be raised from 2.9 megawatts ("MW") to 5.8 MW.

2. Changing the NM pricing structure. IPC proposed to change the NM pricing structure for residential and small general service customers from a system of full retail payment for customer generated power. IPC stated that paying the full retail energy rate to NM customers enables NM customers to unduly reduce what they pay IPC for its costs associated with the non-generation-related components of IPC's revenue requirement. IPC further stated that this situation is unfair to standard service customers, who must then compensate IPC for any revenue shortfall.

   IPC proposed to reduce this inequity by removing recovery of all distribution-related fixed costs from the energy charge and the creation of two new NM tariffs, one for the residential class and one for the small general service class. The new tariffs would (1) increase the monthly service charge from $5.00 to $22.49 for residential service and from $5.00 to $22.49 for small general service; (2) set up a basic load capacity charge ("BLC") of $1.48.per kW for residential service and $1.37 per kW for small general service to

[10] See bill text at http://legiscan.com/CA/text/AB2514/id/665151

reflect the full cost-of-service associated with their use of the distribution system; and (3) uniformly reduce the energy charges for residential and small general service to target the same level of total revenue recovery that would exist under the standard service rate design.

3. Changing how excess net energy is billed. IPC proposed to stop paying customers for excess net energy and instead provide them with a kWh credit for the excess energy they generate in each billing period. The credit would carry forward until the end of the December billing period at which time any remaining credits would expire.

4. Changing tariff provisions regarding interconnection with NM customers. IPC proposed to better define the NM application process and address unauthorized NM installations.

The IPUC reviewed IPC's application at a public hearing held on June 11, 2013. At this hearing, the IPUC entered an order that:

1. Declined to increase the NM cap and instead directed IPC to periodically report on its NM service;

2. Declined to modify the NM pricing structure or move residential and small general service customers into new classes;

3. Required IPC to issue a per kWh credit for excess generation, with credits to expire only when the customer ends service; and

4. Approved revised NM interconnection language.

Louisiana

The Louisiana Public Service Commission ("LPSC") first established rules for NM in November 2005. The LPSC revisited the NM rules in 2011 and made several changes to the rules including a requirement that the LPSC review the rules at such time as a utility's purchase of NM energy reached 0.5 percent of its jurisdictional peak load. The LPSC re-opened the docket in late 2011 to address issues of meter aggregation, and cross-subsidization by non-NM customers. A proposed recommendation was issued by LPSC Staff in November 2012, recommending that in order to remedy the "purchased power subsidy" occurring when a NM customer is credited at retail rate for energy supplied to the grid, the NM customer should only be compensated at the utility's avoided cost, similar to the treatment of Qualifying Facilities ("QFs") under the Public Utility Regulatory Policy Act ("PURPA").

As related to the cross-subsidization issue, the LPSC Staff Report identified three separate subsidies provided to NM customers. These subsidies were categorized as a subsidy for installation (of NM equipment), a purchased power subsidy, and distribution system cost recovery. The Staff Report included recommendations to address each of the indentified subsidies as follows:

1. Utilities should begin charging the incremental difference between the cost of a standard electric meter and a net meter;

2. After stating that LPSC Staff believes it is inappropriate to require electric utilities to purchase wholesale power from NM customers at retail rates, LPSC Staff offers four Options to address the purchased power subsidy:

    a. Option 1 – An excess NM generation rate less than the utility's avoided cost. Under this Option customers would be compensated at a rate $0.01 less than avoided cost to reflect the fact that NM energy is not dispatchable.

    b. Option 2 – An excess NM generation rate equal to avoided cost. Rationalized as the rate that best recognizes the offsetting impacts of non-dispatchable energy from NM customers against the benefits of sharply reduced line losses from NM generators.

    c. Option 3 – An excess NM generation rate above avoided cost, but less than retail. Values the reduced line losses and locational attributes of NM at a recommended $0.01per kWh premium above avoided cost.

    d. Option 4 – An excess net meter generation rate equal to the retail rate (i.e. the existing NM situation). The LPSC Staff note that the cost of NM energy is included in the utility's fuel adjustor and charges to all customers.

3. With regard to distribution cost subsidies, the LPSC Staff recommended that the LPSC wait until the next rate case for each utility before specifically addressing this category of subsidy. However, LPSC staff noted that the most efficient way to alleviate distribution cost subsidies might be to rely less on energy usage rates and instead appropriately adjust the monthly customer charges.

On July 26, 2013, the LPSC ordered that if a utility's NM purchases exceed 0.5 percent of its LPSC jurisdictional peak load, the utility no longer has to accept NM applications. Although LPSC discussed other aspects of its staff's recommendation, the LPSC took no further action.

Virginia

In July 2011, a Virginia state law took effect that allows power companies to collect a standby charge from customers with home NM systems of 10 kilowatts or larger. Dominion Virginia Power ("Dominion") subsequently filed an application with the Commonwealth of Virginia State Corporation Commission ("SCC") to implement such a standby charge. Dominion proposed a standby charge of $4.19 / kW for a DG customer's average peak usage each month for customer systems sized between 10 and 20 kW. Dominion estimated that the average monthly standby charge would be approximately $59.55 per month for a 20 kW[11] DG system. The standby charge would be in addition to the standard $7 monthly connection fee assessed to all customers. The average retail electric rate for such DG customers is approximately $0.11 / kWh. Dominion noted in its application to SCC that the new standby charge would apply to one customer (at the time of the application). Staff has received anecdotal

[11] Virginia state law limits the maximum size of residential NM systems to 20 kW.

information that there are now four Dominion customers that are subject to this standby charge. The SCC approved Dominion's application in November 2011.

<u>Austin Energy (City of Austin, TX)</u>

Austin Energy ("AE") which provides service to the greater Austin, Texas area takes an unusual approach to valuing the benefits of DG solar installations within its service territory. In October 2012, AE implemented a new production-based incentive, in the form of a residential solar rider tariff that acts as an alternative to NM. This rider applies to any customer receiving residential electric service who owns and operates an on-site solar photovoltaic system with a capacity of 20 kW or less that is interconnected with Austin Energy's electric distribution system.

Billable kWh under this rate schedule are based on the customer's total energy consumption during the billing month, including energy delivered by Austin Energy's electric system and energy consumed from an on-site solar system. All non-kWh-based charges under this rate schedule remain unaffected by the application of this rider.

For each billing month, the customer receives a non-refundable credit equal to the metered kWh output of the customer's photovoltaic system, times the current Value-of-Solar Factor plus any carry-over credit from the previous billing month. The Value-of-Solar Factor was initially set at $0.128 per kWh, and is administratively adjusted annually, beginning with each year's January billing month, based upon the marginal cost of displaced energy, avoided capital costs, line loss savings, and environmental benefits. Any amount of solar credit in excess of the customer's total charges for electric service under the residential rate schedule shall be carried forward and applied to the customer's next electric bill. The customer's carry-over credit, if any, shall be reset to zero in the first billing month of each calendar year.

To explain its unique approach to valuing solar DG, and its concerns with traditional NM approaches, AE states:

> "Austin Energy's solar energy incentive programs seek value parity between distributed solar PV options and so-called "conventional generation" options. Austin Energy's approach therefore differs significantly from the traditional "grid parity" objective of equivalent levelized cost of energy between solar and the average utility cost of energy from fully commercialized conventional resources. The goal for Austin Energy is parity in value, not just cost. Beginning with the federal Public Utility Regulatory Act passed by Congress in 1978, utilities generally paid an "avoided cost" value for customer-generated energy, typically set at the marginal price of fuel for an incremental unit of energy. Many states implemented NM policies as an improvement over traditional marginal avoided cost approaches for valuing distributed solar generation, in order to reflect the added value of energy generated at or near the point of consumption. While NM represents a significant improvement in reflecting the value of distributed solar energy compared to the avoided cost approach, problems remain. First, the retail price paid by the customer and credited for solar energy under NM (the value of "spinning the meter backwards") does not necessarily represent and likely under-represents the full value of distributed solar generation."

APPENDIX I

"Second, NM induces two unintended consequences:

1. Solar customers size their solar systems against their baseload level of energy consumption because NM systems typically pay the old avoided cost value for excess generation. This is a practical reflection of the fact that solar capacity is fairly expensive and that excess generation rewards the customer at a very low rate. Of course, most of a solar system's excess generation is delivered to the utility at a time when the value of that energy often greatly exceeds the avoided cost rate.
2. NM value is coupled with consumption. That is, the value to the customer for a kWh of solar energy that offsets a unit of energy consumption is much greater that (sic) the value of excess generation, which is only credited at the avoided cost rate. Austin Energy's experience is that many solar customers recognize and respond to this signal to use more energy, based upon some sense that their consumption is "free" when a solar system is installed."

"Austin Energy designed its new "value of solar" rate to address these unintended consequences and offer an improved, decoupled NM approach."[12]

AE developed a PV Solar Value Calculator ("Calculator") that it uses to annually calculate the Value-of-Solar Factor for application in its production-based incentive. The Calculator is an algorithm that factors in values for system losses, energy savings, generation capacity savings, fuel price hedge value, T&D capacity savings, environmental benefits, and the impacts of nodal pricing in the Electric Reliability Council of Texas ("ERCOT") market.

---

[12] *Designing Austin Energy's Solar Tariff Using a Distributed PV Value Calculator*, Rabago, Norris et al

APPENDIX IIA

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

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

I understand that notwithstanding any other provisions of this Agreement, Arizona Public Service Company ("APS") may file with the Arizona Corporation Commission ("Commission"), pursuant to the Commission's rules and regulations, an application for a change in the requirements, charges, classification, or service, and any rule or regulation relating to APS's interconnection with my rooftop photovoltaic system. In other words, I understand that in the future, upon application by APS or at the Commission's own initiative, the Commission may alter APS's rates, rules or regulations concerning rooftop photovoltaic systems which may affect the cost and/or savings relating to my rooftop photovoltaic system.

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

____
Print Name

____
Signature

____
Date

APPENDIX IIB

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

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

I understand that notwithstanding any other provisions of this Agreement, APS may file with the Arizona Corporation Commission ("Commission"), pursuant to the Commission's rules and regulations, an application for a change in the requirements, charges, classification, or service, and any rule or regulation relating to this rooftop photovoltaic system, as all utility customers are subject to such changes relating to their energy service. The Commission may also, of its own initiative, alter the rates, rules or regulations that pertain to this rooftop photovoltaic system.

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

____
Print Name

____
Signature

____
Date

Appendix III

Assumed Annual Rate of Production 1641 kWh/kW
Retail Rate $0.125

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*B)
D.	Assumed Customer Retail Rate	$0.125	/kWh
E.	Annual Retail Cost of Production	$1,312.80	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.10	/kWh
G.	Annual PPA Cost of Production	$1,050.24	(C*F)
H.	Annual DG Premium	$262.56	(E-G)
I.	Monthly LFCR DG Premium	$21.88	(H/12)
J.	Monthly LFCR DG Premium Per kW	$3.42	(I/A)

A.	Customer DG System Size	6.4	kW
B.	Assumed Annual Rate of Production	1641	kWh/kW
C.	Calculated Annual Production	10,502	kWh (A*B)
D.	Assumed Customer Retail Rate	$0.125	/kWh
E.	Annual Retail Cost of Production	$1,312.80	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.09	/kWh
G.	Annual PPA Cost of Production	$945.22	(C*F)
H.	Annual DG Premium	$367.58	(E-G)
I.	Monthly LFCR DG Premium	$30.63	(H/12)
J.	Monthly LFCR DG Premium Per kW	$4.79	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.125	/kWh
E.	Annual Retail Cost of Production	$1,312.80	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.08	/kWh
G.	Annual PPA Cost of Production	$840.19	(C*F)
H.	Annual DG Premium	$472.61	(E-G)
I.	Monthly LFCR DG Premium	$39.38	(H/12)
J.	Monthly LFCR DG Premium Per kW	$6.15	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.125	/kWh
E.	Annual Retail Cost of Production	$1,312.80	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.07	/kWh
G.	Annual PPA Cost of Production	$735.17	(C*F)
H.	Annual DG Premium	$577.63	(E-G)
I.	Monthly LFCR DG Premium	$48.14	(H/12)
J.	Monthly LFCR DG Premium Per kW	$7.52	(I/A)

Assumed Annual Rate of Production 1641 kWh/kW
Retail Rate $0.130

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*B)
D.	Assumed Customer Retail Rate	$0.130	/kWh
E.	Annual Retail Cost of Production	$1,365.31	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.10	/kWh
G.	Annual PPA Cost of Production	$1,050.24	(C*F)
H.	Annual DG Premium	$315.07	(E-G)
I.	Monthly LFCR DG Premium	$26.26	(H/12)
J.	Monthly LFCR DG Premium Per kW	$4.10	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.130	/kWh
E.	Annual Retail Cost of Production	$1,365.31	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.09	/kWh
G.	Annual PPA Cost of Production	$945.22	(C*F)
H.	Annual DG Premium	$420.10	(E-G)
I.	Monthly LFCR DG Premium	$35.01	(H/12)
J.	Monthly LFCR DG Premium Per kW	$5.47	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.130	/kWh
E.	Annual Retail Cost of Production	$1,365.31	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.08	/kWh
G.	Annual PPA Cost of Production	$840.19	(C*F)
H.	Annual DG Premium	$525.12	(E-G)
I.	Monthly LFCR DG Premium	$43.76	(H/12)
J.	Monthly LFCR DG Premium Per kW	$6.84	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.130	/kWh
E.	Annual Retail Cost of Production	$1,365.31	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.07	/kWh
G.	Annual PPA Cost of Production	$735.17	(C*F)
H.	Annual DG Premium	$630.14	(E-G)
I.	Monthly LFCR DG Premium	$52.51	(H/12)
J.	Monthly LFCR DG Premium Per kW	$8.21	(I/A)

Assumed Annual Rate of Production 1641 kWh/kW
Retail Rate $0.135

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*B)
D.	Assumed Customer Retail Rate	$0.135	/kWh
E.	Annual Retail Cost of Production	$1,417.82	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.10	/kWh
G.	Annual PPA Cost of Production	$1,050.24	(C*F)
H.	Annual DG Premium	$367.58	(E-G)
I.	Monthly LFCR DG Premium	$30.63	(H/12)
J.	Monthly LFCR DG Premium Per kW	$4.79	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.135	/kWh
E.	Annual Retail Cost of Production	$1,417.82	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.09	/kWh
G.	Annual PPA Cost of Production	$945.22	(C*F)
H.	Annual DG Premium	$472.61	(E-G)
I.	Monthly LFCR DG Premium	$39.38	(H/12)
J.	Monthly LFCR DG Premium Per kW	$6.15	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.135	/kWh
E.	Annual Retail Cost of Production	$1,417.82	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.08	/kWh
G.	Annual PPA Cost of Production	$840.19	(C*F)
H.	Annual DG Premium	$577.63	(E-G)
I.	Monthly LFCR DG Premium	$48.14	(H/12)
J.	Monthly LFCR DG Premium Per kW	$7.52	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.135	/kWh
E.	Annual Retail Cost of Production	$1,417.82	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.07	/kWh
G.	Annual PPA Cost of Production	$735.17	(C*F)
H.	Annual DG Premium	$682.66	(E-G)
I.	Monthly LFCR DG Premium	$56.89	(H/12)
J.	Monthly LFCR DG Premium Per kW	$8.89	(I/A)

Assumed Annual Rate of Production 1641 kWh/kW
Retail Rate $0.140

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*B)
D.	Assumed Customer Retail Rate	$0.140	/kWh
E.	Annual Retail Cost of Production	$1,470.34	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.10	/kWh
G.	Annual PPA Cost of Production	$1,050.24	(C*F)
H.	Annual DG Premium	$420.10	(E-G)
I.	Monthly LFCR DG Premium	$35.01	(H/12)
J.	Monthly LFCR DG Premium Per kW	$5.47	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.140	/kWh
E.	Annual Retail Cost of Production	$1,470.34	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.09	/kWh
G.	Annual PPA Cost of Production	$945.22	(C*F)
H.	Annual DG Premium	$525.12	(E-G)
I.	Monthly LFCR DG Premium	$43.76	(H/12)
J.	Monthly LFCR DG Premium Per kW	$6.84	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.140	/kWh
E.	Annual Retail Cost of Production	$1,470.34	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.08	/kWh
G.	Annual PPA Cost of Production	$840.19	(C*F)
H.	Annual DG Premium	$630.14	(E-G)
I.	Monthly LFCR DG Premium	$52.51	(H/12)
J.	Monthly LFCR DG Premium Per kW	$8.21	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.140	/kWh
E.	Annual Retail Cost of Production	$1,470.34	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.07	/kWh
G.	Annual PPA Cost of Production	$735.17	(C*F)
H.	Annual DG Premium	$735.17	(E-G)
I.	Monthly LFCR DG Premium	$61.26	(H/12)
J.	Monthly LFCR DG Premium Per kW	$9.57	(I/A)

PPA prices decrease from left to right
Retail rates increase from top to bottom

Appendix III

Assumed Annual Rate of Production 1641 kWh/kW
Retail Rate $0.145

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*B)
D.	Assumed Customer Retail Rate	$0.145	/kWh
E.	Annual Retail Cost of Production	$1,522.85	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.10	/kWh
G.	Annual PPA Cost of Production	$1,050.24	(C*F)
H.	Annual DG Premium	$472.61	(E-G)
I.	Monthly LFCR DG Premium	$39.38	(H/12)
J.	Monthly LFCR DG Premium Per kW	$6.15	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.145	/kWh
E.	Annual Retail Cost of Production	$1,522.85	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.09	/kWh
G.	Annual PPA Cost of Production	$945.22	(C*F)
H.	Annual DG Premium	$577.63	(E-G)
I.	Monthly LFCR DG Premium	$48.14	(H/12)
J.	Monthly LFCR DG Premium Per kW	$7.52	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.145	/kWh
E.	Annual Retail Cost of Production	$1,522.85	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.08	/kWh
G.	Annual PPA Cost of Production	$840.19	(C*F)
H.	Annual DG Premium	$682.66	(E-G)
I.	Monthly LFCR DG Premium	$56.89	(H/12)
J.	Monthly LFCR DG Premium Per kW	$8.89	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.145	/kWh
E.	Annual Retail Cost of Production	$1,522.85	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.07	/kWh
G.	Annual PPA Cost of Production	$735.17	(C*F)
H.	Annual DG Premium	$787.68	(E-G)
I.	Monthly LFCR DG Premium	$65.64	(H/12)
J.	Monthly LFCR DG Premium Per kW	$10.26	(I/A)

Assumed Annual Rate of Production 1641 kWh/kW
Retail Rate $0.150

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*B)
D.	Assumed Customer Retail Rate	$0.150	/kWh
E.	Annual Retail Cost of Production	$1,575.36	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.10	/kWh
G.	Annual PPA Cost of Production	$1,050.24	(C*F)
H.	Annual DG Premium	$525.12	(E-G)
I.	Monthly LFCR DG Premium	$43.76	(H/12)
J.	Monthly LFCR DG Premium Per kW	$6.84	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.150	/kWh
E.	Annual Retail Cost of Production	$1,575.36	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.09	/kWh
G.	Annual PPA Cost of Production	$945.22	(C*F)
H.	Annual DG Premium	$630.14	(E-G)
I.	Monthly LFCR DG Premium	$52.51	(H/12)
J.	Monthly LFCR DG Premium Per kW	$8.21	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.150	/kWh
E.	Annual Retail Cost of Production	$1,575.36	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.08	/kWh
G.	Annual PPA Cost of Production	$840.19	(C*F)
H.	Annual DG Premium	$735.17	(E-G)
I.	Monthly LFCR DG Premium	$61.26	(H/12)
J.	Monthly LFCR DG Premium Per kW	$9.57	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.150	/kWh
E.	Annual Retail Cost of Production	$1,575.36	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.07	/kWh
G.	Annual PPA Cost of Production	$735.17	(C*F)
H.	Annual DG Premium	$840.19	(E-G)
I.	Monthly LFCR DG Premium	$70.02	(H/12)
J.	Monthly LFCR DG Premium Per kW	$10.94	(I/A)

Marginal Fuel Cost Subtracted From Average Retail Rate

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*B)
D.	Assumed Customer Retail Rate	$0.106	/kWh*
E.	Annual Retail Cost of Production	$1,113.25	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.08	/kWh
G.	Annual PPA Cost of Production	$840.19	(C*F)
H.	Annual DG Premium	$273.06	(E-G)
I.	Monthly LFCR DG Premium	$22.76	(H/12)
J.	Monthly LFCR DG Premium Per kW	$3.56	(I/A)

* Average Retail Rate of $0.137 with $0.031 of fuel taken out

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*B)
D.	Assumed Customer Retail Rate	$0.106	/kWh*
E.	Annual Retail Cost of Production	$1,113.25	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.07	/kWh
G.	Annual PPA Cost of Production	$735.17	(C*F)
H.	Annual DG Premium	$378.09	(E-G)
I.	Monthly LFCR DG Premium	$31.51	(H/12)
J.	Monthly LFCR DG Premium Per kW	$4.92	(I/A)

Low End

A.	Customer DG System Size	6.4	kW
B.	Assumed Annual Rate of Production	1,480	kWh/kW
C.	Calculated Annual Production	9,472	kWh (A*B)
D.	Assumed Customer Retail Rate	$0.125	/kWh
E.	Annual Retail Cost of Production	$1,184.00	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.10	/kWh
G.	Annual PPA Cost of Production	$947.20	(C*F)
H.	Annual DG Premium	$236.80	(E-G)
I.	Monthly LFCR DG Premium	$19.73	(H/12)
J.	Monthly LFCR DG Premium Per kW	$3.08	(I/A)

High End

A.	Customer DG System Size	6.4	kW
B.	Assumed Annual Rate of Production	1,800	kWh/kW
C.	Calculated Annual Production	11,520	kWh (A*B)
D.	Assumed Customer Retail Rate	$0.150	/kWh
E.	Annual Retail Cost of Production	$1,728.00	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.07	/kWh
G.	Annual PPA Cost of Production	$806.40	(C*F)
H.	Annual DG Premium	$921.60	(E-G)
I.	Monthly LFCR DG Premium	$76.80	(H/12)
J.	Monthly LFCR DG Premium Per kW	$12.00	(I/A)

PPA prices decrease from left to right
Retail rates increase from top to bottom

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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. _________ ORDER

Open Meeting
October 16 and 17, 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 intervenor 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

. . .

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.

---

[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").

. . .

---

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

. . .

- The NM Option - ECT-2 Plus NM

  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.

- The Bill Credit Option

  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

---

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

July 2013. These data responses confirm APS's assertion that DG installations have risen over the 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.

<u>The Value of DG</u>

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

---

[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 May 8, 2013, and filed in this docket on July 2, 2013.
[6] Rocky Mountain Institute, *A Review of Solar PV Benefit & Cost Studies*, undated.

for DG as a basis for its alternative recommendations (see *Staff 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.

<u>Staff's Analysis of APS's Proposed Alternatives</u>

<u>ETC-2 Plus NM Option</u>

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

. . .

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.

. . .

[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.

. . .

. . .

Stakeholder Proposals

43. Three alternative cost-shift solution proposals have been received from intervenors 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.

The NM Cost-Shift Issue in Other Jurisdictions

49. 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 this Order.

Staff Recommendations

50. 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.

Staff's Recommendation

Address in Next Rate Case

51. 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.

52. 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 company's 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.

53. 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.

54. 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.

<u>Staff Recommended Alternative #1</u>

<u>LFCR Flat Charge for All New DG Customers</u>

55. 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.

56. 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:

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

57. 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

58. Staff proposes that the LFCR Flat Charge provision become mandatory for all new APS DG customers, unless the customer chooses the ETC-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.

59. 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.

60. 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

---

[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.

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%

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

61. 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.

62. 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."

63. 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)

64. 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.

65. 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.

66. 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

67. 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.

68. 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.

69. Staff has calculated the customer bill impact for Staff's Recommended Alternative #2 for 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%

70. 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

71. 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 October 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.

Staff's Proposed Consumer Protection Advisory

72. 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 Staff's additional language, as shown in Appendix IIA.

73. 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.

. . .

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

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 this issue in Arizona Public Service Company's next general rate case.

ORDER

IT IS THEREFORE ORDERED that the Commission will take no action on the instant application and defer the matter for consideration during Arizona Public Service Company's next rate case.

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, 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 company's individual service territories.

...

...

...

...

...

...

...

IT IS FURTHER ORDERED that 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 Staff's additional language, as shown in Appendix IIA.

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 _______ day of __________________, 2013.

JODI JERICH
EXECUTIVE DIRECTOR

DISSENT: ___________________________

DISSENT: ___________________________

SMO:RLB:lhm\MAS

SERVICE LIST FOR: Arizona Public Service Company
DOCKET NO. E-01345A-13-0248

Mr. Kevin Fox
Ms. Erica Schroeder
Mr. Tim Lindl
Keyes, Fox & Wiedman LLP
436 14th St. - 1305
Oakland, California 94612

Mr. Timothy Hogan
Arizona Center for Law in the Public Interest
202 E. McDowell Rd. - 153
Phoenix, Arizona 85004

Mr. Thomas Loquvam
Ms. Deborah R. Scott
Pinnacle West Capital Corporation
400 N. 5Th St, MS 8695
Phoenix, , Arizona 85004

Mr. Michael Patten
Mr. Jason Gellman
Roshka DeWulf & Patten, PLC
One Arizona Center
400 E. Van Buren St. - 800
Phoenix, Arizona 85004

Mr. Greg Patterson
916 W. Adams - 3
Phoenix, Arizona 85007

Mr. Daniel Pozefsky
RUCO
1110 West Washington, Suite 220
Phoenix, Arizona 85007

Mr. Giancarlo Estrada
Estrada-Legal, PC
One E. Camelback Rd, - 550
Phoenix, Arizona 85012

Mr. Garry Hays
1702 E. Highland Ave. - 204
Phoenix, Arizona 85016

Mr. Court Rich
Rose Law Group
6613 N. Scottsdale Rd., Ste. 200
Scottsdale, Arizona 85250

Ms. Patty Ihle
304 E. Cedar Mill Rd
Star Valley, Arizona 85541

Mr. Hugh Hallman
Hallman & Affiliates, PC
2011 N. Campo Alegre Rd. - 100
Tempe, Arizona 85281

Mr. John Wallace
2210 South Priest Dr
Tempe, Arizona 85282

Mr. Lewis Levenson
1308 E. Cedar Lane
Payson, Arizona 85541

Mr. Bradley Carroll
Ms. Kimberly A. Ruht
88 E. Broadway Blvd. MS HQE910
P.O. Box 711
Tucson, Arizona 85702

Mr. Todd Glass
Mr. Keene M. O'Connor
Wilson Sonsini Goodrich & Rosati, PC
701 Fifth Ave. - 5100
Seattle, Washington 98104

Mr. David Berry
Western Resource Advocates
PO Box 1064
Scottsdale AZ 85252-1064

Mr. Mark Holohan, Chairman
Arizona Solar Energy Industries Association
2221 West Lone Cactus Drive, Suite 2
Phoenix, Arizona 85027

Ms. Anne Smart, Exec. Director
Alliance for Solar Choice
45 Fremont Street, 32nd Floor
San Francisco, CA 94105

Mr. Steven M. Olea
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Ms. Janice M. Alward
Chief Counsel, Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

California

The California State Legislature passed Assembly Bill 2514[10] in September 2012 that directed the California Public Utilities Commission ("CPUC") to complete a study analyzing the full costs and benefits of the state's NM program. The bill further requires the CPUC to determine the extent to which NM customers pay for the full costs of electric services provided by the utilities. Specifically, the bill requires a study "...to determine who benefits from, and who bears the economic burden, if any, of the net energy metering program, and to determine the extent to which each class of ratepayers and each region of the state receiving service under the net energy metering program is paying the full cost of the services provided to them by electrical corporations, and the extent to which those customers pay their share of the costs of public purpose programs." The CPUC is required to complete the report by October 1, 2013, and deliver the results of the report to the Legislature within 30 days of its completion.

A second California State Legislature bill, AB 327, was recently passed by the state Assembly and forwarded to the California Governor for signature. This bill addresses residential electric rate reforms and provides a vehicle for extending the state's solar NM program, which otherwise faced expiration in 2014. The bill sets up a specific process for developing a new state-wide NM program. In addition, the bill authorizes the CPUC to: (1) lower the ramp on California's tiered energy rates; (2) increase monthly customer charges by up to $10 per month; and (3) clarifies the methodology of calculating each utility company's NM capacity cap.

Idaho

On November 30, 2012, Idaho Power Company ("IPC") applied to the Idaho Public Utilities Commission ("IPUC") to modify its NM service. IPC's application requested that IPUC approve four changes to IPC's NM service:

1. Increasing the NM capacity cap. IPC requested that the ceiling for the amount of NM capacity be raised from 2.9 megawatts ("MW") to 5.8 MW.

2. Changing the NM pricing structure. IPC proposed to change the NM pricing structure for residential and small general service customers from a system of full retail payment for customer generated power. IPC stated that paying the full retail energy rate to NM customers enables NM customers to unduly reduce what they pay IPC for its costs associated with the non-generation-related components of IPC's revenue requirement. IPC further stated that this situation is unfair to standard service customers, who must then compensate IPC for any revenue shortfall.

   IPC proposed to reduce this inequity by removing recovery of all distribution-related fixed costs from the energy charge and the creation of two new NM tariffs, one for the residential class and one for the small general service class. The new tariffs would (1) increase the monthly service charge from $5.00 to $22.49 for residential service and from $5.00 to $22.49 for small general service; (2) set up a basic load capacity charge ("BLC") of $1.48.per kW for residential service and $1.37 per kW for small general service to

[10] See bill text at http://legiscan.com/CA/text/AB2514/id/665151

reflect the full cost-of-service associated with their use of the distribution system; and (3) uniformly reduce the energy charges for residential and small general service to target the same level of total revenue recovery that would exist under the standard service rate design.

3. Changing how excess net energy is billed. IPC proposed to stop paying customers for excess net energy and instead provide them with a kWh credit for the excess energy they generate in each billing period. The credit would carry forward until the end of the December billing period at which time any remaining credits would expire.

4. Changing tariff provisions regarding interconnection with NM customers. IPC proposed to better define the NM application process and address unauthorized NM installations.

The IPUC reviewed IPC's application at a public hearing held on June 11, 2013. At this hearing, the IPUC entered an order that:

1. Declined to increase the NM cap and instead directed IPC to periodically report on its NM service;

2. Declined to modify the NM pricing structure or move residential and small general service customers into new classes;

3. Required IPC to issue a per kWh credit for excess generation, with credits to expire only when the customer ends service; and

4. Approved revised NM interconnection language.

Louisiana

The Louisiana Public Service Commission ("LPSC") first established rules for NM in November 2005. The LPSC revisited the NM rules in 2011 and made several changes to the rules including a requirement that the LPSC review the rules at such time as a utility's purchase of NM energy reached 0.5 percent of its jurisdictional peak load. The LPSC re-opened the docket in late 2011 to address issues of meter aggregation, and cross-subsidization by non-NM customers. A proposed recommendation was issued by LPSC Staff in November 2012, recommending that in order to remedy the "purchased power subsidy" occurring when a NM customer is credited at retail rate for energy supplied to the grid, the NM customer should only be compensated at the utility's avoided cost, similar to the treatment of Qualifying Facilities ("QFs") under the Public Utility Regulatory Policy Act ("PURPA").

As related to the cross-subsidization issue, the LPSC Staff Report identified three separate subsidies provided to NM customers. These subsidies were categorized as a subsidy for installation (of NM equipment), a purchased power subsidy, and distribution system cost recovery. The Staff Report included recommendations to address each of the indentified subsidies as follows:

1. Utilities should begin charging the incremental difference between the cost of a standard electric meter and a net meter;

2. After stating that LPSC Staff believes it is inappropriate to require electric utilities to purchase wholesale power from NM customers at retail rates, LPSC Staff offers four Options to address the purchased power subsidy:

    a. Option 1 – <u>An excess NM generation rate less than the utility's avoided cost</u>. Under this Option customers would be compensated at a rate $0.01 less than avoided cost to reflect the fact that NM energy is not dispatchable.

    b. Option 2 – <u>An excess NM generation rate equal to avoided cost.</u> Rationalized as the rate that best recognizes the offsetting impacts of non-dispatchable energy from NM customers against the benefits of sharply reduced line losses from NM generators.

    c. Option 3 – <u>An excess NM generation rate above avoided cost, but less than retail.</u> Values the reduced line losses and locational attributes of NM at a recommended $0.01per kWh premium above avoided cost.

    d. Option 4 – <u>An excess net meter generation rate equal to the retail rate (i.e. the existing NM situation).</u> The LPSC Staff note that the cost of NM energy is included in the utility's fuel adjustor and charges to all customers.

3. With regard to distribution cost subsidies, the LPSC Staff recommended that the LPSC wait until the next rate case for each utility before specifically addressing this category of subsidy. However, LPSC staff noted that the most efficient way to alleviate distribution cost subsidies might be to rely less on energy usage rates and instead appropriately adjust the monthly customer charges.

On July 26, 2013, the LPSC ordered that if a utility's NM purchases exceed 0.5 percent of its LPSC jurisdictional peak load, the utility no longer has to accept NM applications. Although LPSC discussed other aspects of its staff's recommendation, the LPSC took no further action.

<u>Virginia</u>

In July 2011, a Virginia state law took effect that allows power companies to collect a standby charge from customers with home NM systems of 10 kilowatts or larger. Dominion Virginia Power ("Dominion") subsequently filed an application with the Commonwealth of Virginia State Corporation Commission ("SCC") to implement such a standby charge. Dominion proposed a standby charge of $4.19 / kW for a DG customer's average peak usage each month for customer systems sized between 10 and 20 kW. Dominion estimated that the average monthly standby charge would be approximately $59.55 per month for a 20 kW[11] DG system. The standby charge would be in addition to the standard $7 monthly connection fee assessed to all customers. The average retail electric rate for such DG customers is approximately $0.11 / kWh. Dominion noted in its application to SCC that the new standby charge would apply to one customer (at the time of the application). Staff has received anecdotal

[11] Virginia state law limits the maximum size of residential NM systems to 20 kW.

information that there are now four Dominion customers that are subject to this standby charge. The SCC approved Dominion's application in November 2011.

Austin Energy (City of Austin, TX)

Austin Energy ("AE") which provides service to the greater Austin, Texas area takes an unusual approach to valuing the benefits of DG solar installations within its service territory. In October 2012, AE implemented a new production-based incentive, in the form of a residential solar rider tariff that acts as an alternative to NM. This rider applies to any customer receiving residential electric service who owns and operates an on-site solar photovoltaic system with a capacity of 20 kW or less that is interconnected with Austin Energy's electric distribution system.

Billable kWh under this rate schedule are based on the customer's total energy consumption during the billing month, including energy delivered by Austin Energy's electric system and energy consumed from an on-site solar system. All non-kWh-based charges under this rate schedule remain unaffected by the application of this rider.

For each billing month, the customer receives a non-refundable credit equal to the metered kWh output of the customer's photovoltaic system, times the current Value-of-Solar Factor plus any carry-over credit from the previous billing month. The Value-of-Solar Factor was initially set at $0.128 per kWh, and is administratively adjusted annually, beginning with each year's January billing month, based upon the marginal cost of displaced energy, avoided capital costs, line loss savings, and environmental benefits. Any amount of solar credit in excess of the customer's total charges for electric service under the residential rate schedule shall be carried forward and applied to the customer's next electric bill. The customer's carry-over credit, if any, shall be reset to zero in the first billing month of each calendar year.

To explain its unique approach to valuing solar DG, and its concerns with traditional NM approaches, AE states:

> "Austin Energy's solar energy incentive programs seek value parity between distributed solar PV options and so-called "conventional generation" options. Austin Energy's approach therefore differs significantly from the traditional "grid parity" objective of equivalent levelized cost of energy between solar and the average utility cost of energy from fully commercialized conventional resources. The goal for Austin Energy is parity in value, not just cost. Beginning with the federal Public Utility Regulatory Act passed by Congress in 1978, utilities generally paid an "avoided cost" value for customer-generated energy, typically set at the marginal price of fuel for an incremental unit of energy. Many states implemented NM policies as an improvement over traditional marginal avoided cost approaches for valuing distributed solar generation, in order to reflect the added value of energy generated at or near the point of consumption. While NM represents a significant improvement in reflecting the value of distributed solar energy compared to the avoided cost approach, problems remain. First, the retail price paid by the customer and credited for solar energy under NM (the value of "spinning the meter backwards") does not necessarily represent and likely under-represents the full value of distributed solar generation."

"Second, NM induces two unintended consequences:

1. Solar customers size their solar systems against their baseload level of energy consumption because NM systems typically pay the old avoided cost value for excess generation. This is a practical reflection of the fact that solar capacity is fairly expensive and that excess generation rewards the customer at a very low rate. Of course, most of a solar system's excess generation is delivered to the utility at a time when the value of that energy often greatly exceeds the avoided cost rate.
2. NM value is coupled with consumption. That is, the value to the customer for a kWh of solar energy that offsets a unit of energy consumption is much greater that (sic) the value of excess generation, which is only credited at the avoided cost rate. Austin Energy's experience is that many solar customers recognize and respond to this signal to use more energy, based upon some sense that their consumption is "free" when a solar system is installed."

"Austin Energy designed its new "value of solar" rate to address these unintended consequences and offer an improved, decoupled NM approach."[12]

AE developed a PV Solar Value Calculator ("Calculator") that it uses to annually calculate the Value-of-Solar Factor for application in its production-based incentive. The Calculator is an algorithm that factors in values for system losses, energy savings, generation capacity savings, fuel price hedge value, T&D capacity savings, environmental benefits, and the impacts of nodal pricing in the Electric Reliability Council of Texas ("ERCOT") market.

[12] *Designing Austin Energy's Solar Tariff Using a Distributed PV Value Calculator*, Rabago, Norris et al

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

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

I understand that notwithstanding any other provisions of this Agreement, Arizona Public Service Company ("APS") may file with the Arizona Corporation Commission ("Commission"), pursuant to the Commission's rules and regulations, an application for a change in the requirements, charges, classification, or service, and any rule or regulation relating to APS's interconnection with my rooftop photovoltaic system. In other words, I understand that in the future, upon application by APS or at the Commission's own initiative, the Commission may alter APS's rates, rules or regulations concerning rooftop photovoltaic systems which may affect the cost and/or savings relating to my rooftop photovoltaic system.

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

____

Print Name

____

Signature

____

Date

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

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

I understand that notwithstanding any other provisions of this Agreement, APS may file with the Arizona Corporation Commission ("Commission"), pursuant to the Commission's rules and regulations, an application for a change in the requirements, charges, classification, or service, and any rule or regulation relating to this rooftop photovoltaic system, as all utility customers are subject to such changes relating to their energy service. The Commission may also, of its own initiative, alter the rates, rules or regulations that pertain to this rooftop photovoltaic system.

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

____
Print Name

____
Signature

____
Date

Appendix III

Assumed Annual Rate of Production 1641 kWh/kW
Retail Rate $0.125

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*B)
D.	Assumed Customer Retail Rate	$0.125	/kWh
E.	Annual Retail Cost of Production	$1,312.80	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.10	/kWh
G.	Annual PPA Cost of Production	$1,050.24	(C*F)
H.	Annual DG Premium	$262.56	(E-G)
I.	Monthly LFCR DG Premium	$21.88	(H/12)
J.	Monthly LFCR DG Premium Per kW	$3.42	(I/A)

A.	Customer DG System Size	6.4	kW
B.	Assumed Annual Rate of Production	1641	kWh/kW
C.	Calculated Annual Production	10,502	kWh (A*B)
D.	Assumed Customer Retail Rate	$0.125	/kWh
E.	Annual Retail Cost of Production	$1,312.80	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.09	/kWh
G.	Annual PPA Cost of Production	$945.22	(C*F)
H.	Annual DG Premium	$367.58	(E-G)
I.	Monthly LFCR DG Premium	$30.63	(H/12)
J.	Monthly LFCR DG Premium Per kW	$4.79	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.125	/kWh
E.	Annual Retail Cost of Production	$1,312.80	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.08	/kWh
G.	Annual PPA Cost of Production	$840.19	(C*F)
H.	Annual DG Premium	$472.61	(E-G)
I.	Monthly LFCR DG Premium	$39.38	(H/12)
J.	Monthly LFCR DG Premium Per kW	$6.15	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.125	/kWh
E.	Annual Retail Cost of Production	$1,312.80	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.07	/kWh
G.	Annual PPA Cost of Production	$735.17	(C*F)
H.	Annual DG Premium	$577.63	(E-G)
I.	Monthly LFCR DG Premium	$48.14	(H/12)
J.	Monthly LFCR DG Premium Per kW	$7.52	(I/A)

Assumed Annual Rate of Production 1641 kWh/kW
Retail Rate $0.130

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*B)
D.	Assumed Customer Retail Rate	$0.130	/kWh
E.	Annual Retail Cost of Production	$1,365.31	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.10	/kWh
G.	Annual PPA Cost of Production	$1,050.24	(C*F)
H.	Annual DG Premium	$315.07	(E-G)
I.	Monthly LFCR DG Premium	$26.26	(H/12)
J.	Monthly LFCR DG Premium Per kW	$4.10	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.130	/kWh
E.	Annual Retail Cost of Production	$1,365.31	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.09	/kWh
G.	Annual PPA Cost of Production	$945.22	(C*F)
H.	Annual DG Premium	$420.10	(E-G)
I.	Monthly LFCR DG Premium	$35.01	(H/12)
J.	Monthly LFCR DG Premium Per kW	$5.47	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.130	/kWh
E.	Annual Retail Cost of Production	$1,365.31	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.08	/kWh
G.	Annual PPA Cost of Production	$840.19	(C*F)
H.	Annual DG Premium	$525.12	(E-G)
I.	Monthly LFCR DG Premium	$43.76	(H/12)
J.	Monthly LFCR DG Premium Per kW	$6.84	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.130	/kWh
E.	Annual Retail Cost of Production	$1,365.31	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.07	/kWh
G.	Annual PPA Cost of Production	$735.17	(C*F)
H.	Annual DG Premium	$630.14	(E-G)
I.	Monthly LFCR DG Premium	$52.51	(H/12)
J.	Monthly LFCR DG Premium Per kW	$8.21	(I/A)

Assumed Annual Rate of Production 1641 kWh/kW
Retail Rate $0.135

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*B)
D.	Assumed Customer Retail Rate	$0.135	/kWh
E.	Annual Retail Cost of Production	$1,417.82	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.10	/kWh
G.	Annual PPA Cost of Production	$1,050.24	(C*F)
H.	Annual DG Premium	$367.58	(E-G)
I.	Monthly LFCR DG Premium	$30.63	(H/12)
J.	Monthly LFCR DG Premium Per kW	$4.79	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.135	/kWh
E.	Annual Retail Cost of Production	$1,417.82	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.09	/kWh
G.	Annual PPA Cost of Production	$945.22	(C*F)
H.	Annual DG Premium	$472.61	(E-G)
I.	Monthly LFCR DG Premium	$39.38	(H/12)
J.	Monthly LFCR DG Premium Per kW	$6.15	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.135	/kWh
E.	Annual Retail Cost of Production	$1,417.82	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.08	/kWh
G.	Annual PPA Cost of Production	$840.19	(C*F)
H.	Annual DG Premium	$577.63	(E-G)
I.	Monthly LFCR DG Premium	$48.14	(H/12)
J.	Monthly LFCR DG Premium Per kW	$7.52	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.135	/kWh
E.	Annual Retail Cost of Production	$1,417.82	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.07	/kWh
G.	Annual PPA Cost of Production	$735.17	(C*F)
H.	Annual DG Premium	$682.66	(E-G)
I.	Monthly LFCR DG Premium	$56.89	(H/12)
J.	Monthly LFCR DG Premium Per kW	$8.89	(I/A)

Assumed Annual Rate of Production 1641 kWh/kW
Retail Rate $0.140

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*B)
D.	Assumed Customer Retail Rate	$0.140	/kWh
E.	Annual Retail Cost of Production	$1,470.34	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.10	/kWh
G.	Annual PPA Cost of Production	$1,050.24	(C*F)
H.	Annual DG Premium	$420.10	(E-G)
I.	Monthly LFCR DG Premium	$35.01	(H/12)
J.	Monthly LFCR DG Premium Per kW	$5.47	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.140	/kWh
E.	Annual Retail Cost of Production	$1,470.34	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.09	/kWh
G.	Annual PPA Cost of Production	$945.22	(C*F)
H.	Annual DG Premium	$525.12	(E-G)
I.	Monthly LFCR DG Premium	$43.76	(H/12)
J.	Monthly LFCR DG Premium Per kW	$6.84	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.140	/kWh
E.	Annual Retail Cost of Production	$1,470.34	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.08	/kWh
G.	Annual PPA Cost of Production	$840.19	(C*F)
H.	Annual DG Premium	$630.14	(E-G)
I.	Monthly LFCR DG Premium	$52.51	(H/12)
J.	Monthly LFCR DG Premium Per kW	$8.21	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.140	/kWh
E.	Annual Retail Cost of Production	$1,470.34	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.07	/kWh
G.	Annual PPA Cost of Production	$735.17	(C*F)
H.	Annual DG Premium	$735.17	(E-G)
I.	Monthly LFCR DG Premium	$61.26	(H/12)
J.	Monthly LFCR DG Premium Per kW	$9.57	(I/A)

PPA prices decrease from left to right
Retail rates increase from top to bottom

Assumed Annual Rate of Production 1641 kWh/kW
Retail Rate $0.145

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*B)
D.	Assumed Customer Retail Rate	$0.145	/kWh
E.	Annual Retail Cost of Production	$1,522.85	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.10	/kWh
G.	Annual PPA Cost of Production	$1,050.24	(C*F)
H.	Annual DG Premium	$472.61	(E-G)
I.	Monthly LFCR DG Premium	$39.38	(H/12)
J.	Monthly LFCR DG Premium Per kW	$6.15	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.145	/kWh
E.	Annual Retail Cost of Production	$1,522.85	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.09	/kWh
G.	Annual PPA Cost of Production	$945.22	(C*F)
H.	Annual DG Premium	$577.63	(E-G)
I.	Monthly LFCR DG Premium	$48.14	(H/12)
J.	Monthly LFCR DG Premium Per kW	$7.52	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.145	/kWh
E.	Annual Retail Cost of Production	$1,522.85	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.08	/kWh
G.	Annual PPA Cost of Production	$840.19	(C*F)
H.	Annual DG Premium	$682.66	(E-G)
I.	Monthly LFCR DG Premium	$56.89	(H/12)
J.	Monthly LFCR DG Premium Per kW	$8.89	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.145	/kWh
E.	Annual Retail Cost of Production	$1,522.85	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.07	/kWh
G.	Annual PPA Cost of Production	$735.17	(C*F)
H.	Annual DG Premium	$787.68	(E-G)
I.	Monthly LFCR DG Premium	$65.64	(H/12)
J.	Monthly LFCR DG Premium Per kW	$10.26	(I/A)

Assumed Annual Rate of Production 1641 kWh/kW
Retail Rate $0.150

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*B)
D.	Assumed Customer Retail Rate	$0.150	/kWh
E.	Annual Retail Cost of Production	$1,575.36	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.10	/kWh
G.	Annual PPA Cost of Production	$1,050.24	(C*F)
H.	Annual DG Premium	$525.12	(E-G)
I.	Monthly LFCR DG Premium	$43.76	(H/12)
J.	Monthly LFCR DG Premium Per kW	$6.84	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.150	/kWh
E.	Annual Retail Cost of Production	$1,575.36	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.09	/kWh
G.	Annual PPA Cost of Production	$945.22	(C*F)
H.	Annual DG Premium	$630.14	(E-G)
I.	Monthly LFCR DG Premium	$52.51	(H/12)
J.	Monthly LFCR DG Premium Per kW	$8.21	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.150	/kWh
E.	Annual Retail Cost of Production	$1,575.36	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.08	/kWh
G.	Annual PPA Cost of Production	$840.19	(C*F)
H.	Annual DG Premium	$735.17	(E-G)
I.	Monthly LFCR DG Premium	$61.26	(H/12)
J.	Monthly LFCR DG Premium Per kW	$9.57	(I/A)

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*B)
D.	Assumed Customer Retail Rate	$0.150	/kWh
E.	Annual Retail Cost of Production	$1,575.36	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.07	/kWh
G.	Annual PPA Cost of Production	$735.17	(C*F)
H.	Annual DG Premium	$840.19	(E-G)
I.	Monthly LFCR DG Premium	$70.02	(H/12)
J.	Monthly LFCR DG Premium Per kW	$10.94	(I/A)

Marginal Fuel Cost Subtracted From Average Retail Rate

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*B)
D.	Assumed Customer Retail Rate	$0.106	/kWh*
E.	Annual Retail Cost of Production	$1,113.25	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.08	/kWh
G.	Annual PPA Cost of Production	$840.19	(C*F)
H.	Annual DG Premium	$273.06	(E-G)
I.	Monthly LFCR DG Premium	$22.76	(H/12)
J.	Monthly LFCR DG Premium Per kW	$3.56	(I/A)

* Average Retail Rate of $0.137 with $0.031 of fuel taken out

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*B)
D.	Assumed Customer Retail Rate	$0.106	/kWh*
E.	Annual Retail Cost of Production	$1,113.25	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.07	/kWh
G.	Annual PPA Cost of Production	$735.17	(C*F)
H.	Annual DG Premium	$378.09	(E-G)
I.	Monthly LFCR DG Premium	$31.51	(H/12)
J.	Monthly LFCR DG Premium Per kW	$4.92	(I/A)

Low End

A.	Customer DG System Size	6.4	kW
B.	Assumed Annual Rate of Production	1,480	kWh/kW
C.	Calculated Annual Production	9,472	kWh (A*B)
D.	Assumed Customer Retail Rate	$0.125	/kWh
E.	Annual Retail Cost of Production	$1,184.00	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.10	/kWh
G.	Annual PPA Cost of Production	$947.20	(C*F)
H.	Annual DG Premium	$236.80	(E-G)
I.	Monthly LFCR DG Premium	$19.73	(H/12)
J.	Monthly LFCR DG Premium Per kW	$3.08	(I/A)

DeDDecision No.

High End

A.	Customer DG System Size	6.4	kW
B.	Assumed Annual Rate of Production	1,800	kWh/kW
C.	Calculated Annual Production	11,520	kWh (A*B)
D.	Assumed Customer Retail Rate	$0.150	/kWh
E.	Annual Retail Cost of Production	$1,728.00	(C*D)
F.	Assumed Utility Scale PPA Rate	$0.07	/kWh
G.	Annual PPA Cost of Production	$806.40	(C*F)
H.	Annual DG Premium	$921.60	(E-G)
I.	Monthly LFCR DG Premium	$76.80	(H/12)
J.	Monthly LFCR DG Premium Per kW	$12.00	(I/A)

PPA prices decrease from left to right
Retail rates increase from top to bottom