BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	Docket No. E-01345A-16-0036

DIRECT TESTIMONY AND EXHIBIT OF BRIANA KOBOR

ON BEHALF OF VOTE SOLAR

FEBRUARY 3, 2017

Table of Contents

List of Tables

List of Figures

1 Introduction

Q. Please state your name and business address.

A. My name is Briana Kobor. My business address is 360 22nd Street, Suite 730, Oakland, CA.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting this testimony on behalf of Vote Solar.

Q. What is Vote Solar?

A. Vote Solar is a non-profit grassroots organization working to foster economic opportunity, promote energy independence, and fight climate change by making solar a mainstream energy resource across the United States. Since 2002, Vote Solar has engaged in state, local, and federal advocacy campaigns to remove regulatory barriers and implement key policies needed to bring solar to scale. Vote Solar has approximately 60,000 members nationally and 3,500 in Arizona.

Q. By whom are you employed and in what capacity?

A. I serve as Program Director of Distributed Generation ("DG") Regulatory Policy for Vote Solar. I analyze policy initiatives, development, and implementation related to distributed solar generation. I also review regulatory filings, perform technical analyses, and testify in commission proceedings relating to distributed solar generation.

Q. Please describe your education and experience.

A. I have a degree in Environmental Economics and Policy from the University of California, Berkeley and I have been employed in the utility regulatory industry since 2007. Prior to joining Vote Solar in August 2015, I was employed for eight years by MRW & Associates, LLC ("MRW"), which is a specialized energy consulting firm. At MRW, I focused on electricity and natural gas markets, ratemaking, utility regulation, and energy policy development. I worked with a variety of clients including energy policy makers, developers, suppliers, and end-users. My clients included the California Public Utilities Commission, the California Energy Commission, the California Independent System Operator, and several publicly owned utilities. I have experience evaluating utility cost-of-service studies, revenue allocation and ratemaking, wholesale and retail electric rate forecasting, asset valuation, and financial analyses. A summary of my background and qualifications is attached as Exhibit BK-1.

Q. Have you previously testified before the Arizona Corporation Commission (the "Commission")?

A. Yes. I provided testimony in Docket No. E-04204A-l5-0142, the most recent UNS Electric, Inc. General Rate Case; Docket No. E-00000J-14-0023, entitled "In the Matter of the Commission's Investigation of Value and Cost of Distributed Generation"; and Docket No. E-01933A-15-0322, the most recent Tucson Electric Power Company General Rate Case.

Q. Have you previously testified before other regulatory commissions?

A. Yes. I testified in proceedings before the California Public Utilities Commission. I testified on behalf of the Coalition for Affordable Streetlights in A.14-06-014 Application of Southern California Edison Company (U338E) to Establish Marginal Costs, Allocate Revenues, Design Rates, and Implement Additional Dynamic Pricing Rates. I also testified on behalf of the Utility Consumers' Action Network in A.14-11-003 Application of San Diego Gas & Electric Company (U902M) for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2016.

2 Purpose of Testimony and Summary of Recommendations

Q. What is the purpose of your testimony in this proceeding?

A. My testimony addresses certain rate design proposals put forth by Arizona Public Service Company ("APS" or "the Company") in its general rate case application. Among its rate design proposals, the Company requests significant changes to rate design for residential and extra small commercial customers and modifications to the compensation structure that customers receive for exported DG. The specific proposals I address in my testimony include: (1) the proposal to implement mandatory demand charges on the majority of residential and all extra small commercial customers, (2) the proposal to restrict new residential DG customers to a single rate option that includes a demand charge, (3) the proposal to redefine the peak period for residential and extra small commercial customers, (4) the proposal to increase the basic service charges for residential and extra small commercial customers, (5) the proposal to grandfather net metering customers, (6) the proposal to restrict enrollment on modified net metering to customers with DG systems less than 100 kW, and (7) the proposal to modify the Lost Fixed Cost Recovery Mechanism ("LFCR"). There are a number of additional proposals in APS's application that are not addressed in my testimony, but that does not imply that I agree with those proposals. I reserve the opportunity to discuss any additional proposals not addressed in my direct testimony through surrebuttal testimony.

Q. Please describe how your testimony is organized.

A. The remainder of my testimony consists of six major sections. In the first section I summarize APS's rationale for the rate design proposals listed above. In the second section I examine APS's claim that the current rate design for DG customers results in a cost shift to other residential customers. In the third section I examine whether mandatory demand charges for residential and extra small commercial customers are in the public interest. In the fourth section I examine whether APS's proposal to restrict the rate options for new DG customers is warranted based on the evidence. In the fifth section I present Vote Solar's rate design proposals. Finally, the sixth section provides a summary of my recommendations.

Q. Please summarize your findings and recommendations.

A. APS proposes overhauling its residential and small business customer rates to include mandatory demand charges and significant increases in fixed customer charges. In addition, APS proposes restricting the rate options available to new DG customers and limiting enrollment in the modified net metering tariff to DG systems below 100 kW in size.

In support of these proposals, APS's application relies on its allegation that current rate design for all residential customers, and specifically solar customers, does not accurately reflect the cost of providing service and results in unfair rate treatment. To support this allegation, APS produced a cost-of-service study ("COSS") purporting to show that solar customers on energy rates pay only 38% of the cost APS incurs to serve them and that solar customers on demand rates pay only 71% of the cost to serve them. APS extrapolates these results to contend that DG customers currently shift $28-72 per month to non-DG customers, which will result in a $1 billion cost shift over 20 years from grandfathered solar customers (assuming all else stays the same). APS claims that its proposed demand charges correct these alleged problems.

I reviewed APS's COSS and found that APS employed numerous inappropriate assumptions that result in an over-allocation of costs to solar customers and significantly skew its results. I recommend that three assumptions employed by APS be modified:

1. **Costs should be allocated to all customers based on the loads actually served by APS (delivered loads):** APS proposes allocating costs to solar customers based on the "total load" at the customer's home, which includes

load served by APS (the “delivered load”) and load served by the customer’s onsite rooftop solar system. However, APS only incurs costs to serve customers’ delivered load. The individual customer incurs a private investment cost to serve that portion of her own electricity load that her solar system serves. It is inappropriate for APS to reach behind the meter and charge customers (through allocation in the cost-of-service study) for services provided by the customer’s own investment and not provided by the utility. As I will demonstrate later in my testimony, the Commission’s Value of DG decision recognizes this distinction and APS’s arguments that their methodology captures costs associated with grid services for the rooftop solar customer’s export of energy and backup of the customer’s self-supplied generation are unfounded. I conclude that allocating costs based on delivered load fully captures costs associated with serving all customers, with and without solar generation.

2. **Non-coincident peak (“NCP”) demand used for cost allocation should not be separated by tariff option:** It is a commonly accepted practice to use class NCP as an allocator for costs associated with the primary distribution system and distribution substations in utility cost-of-service studies. This method approximates loading on distribution system components that must be designed to meet the peak unique to the group of all customers served by each component. In contrast, APS’s COSS applies a separate NCP allocator for each residential tariff option: E-12, ET-2, etc. This assumes that specific distribution equipment serves primarily customers in each separate tariff option (i.e., substations and feeders serving E-12 customers are different from those serving ET-2 customers, which are also different from those serving ECT-2 customers). There is no evidence to support this implicit assumption. Moreover, the general assumption that class-wide peaks represent peaks on specific distribution equipment because such equipment serves predominantly a single class does not hold true for separate tariffs with dispersed customers.

As I demonstrate in my testimony, APS's attempt to allocate to tariff NCP rather than class-wide NCP over allocates costs to the residential class as a whole and an over allocates costs to solar customers by an even larger degree. I conclude that residential tariff-specific allocators should be replaced with a class NCP allocator to reflect the actual residential class peak.

3. **The cost of service study should treat residential customers with and without solar the same in terms of customer-related costs:** When a customer installs DG she requires different metering equipment. APS will replace the standard residential meter with a bi-directional billing meter and will additionally install a production meter. The bi-directional billing meter handles all billing functions for the DG customer and is required for measurement of exported generation. The production meter is used by the utility to measure total solar output for RES compliance purposes. APS proposes charging solar customers for the cost of both bi-directional meters and solar production meters in the COSS. As I demonstrate in my testimony, this methodology is inconsistent with the ALJ's Recommended Opinion and Order in the Tucson Electric Power Company ("TEP") rate case and should be revised to treat residential customers with and without solar the same in terms of customer-related costs. Incremental capital and labor costs associated with solar customers' bi-directional meters should be recovered through a meter fee.

I conducted an analysis of the relative cost to serve APS's subgroups of residential customers that corrects for these three assumptions and found that solar customers on both energy and demand rates pay more than their fair share of costs with APS's current rate design options. When reasonable assumptions are employed, the analysis clearly demonstrates that there is no cost shift related to solar under current rate design. In fact, solar customers on energy rates are currently paying $7 per month greater than their share of costs, and solar customers on demand rates are currently paying $17 greater than their share of costs under current rate design. When combined with conservative assumptions regarding the costs and benefits of exported solar generation, I find that contrary to APS's claim of a $1 billion cost shift, the results demonstrate that solar customers provide a $60 million net benefit to other customers by choosing to install rooftop solar generation.

Additionally, I find that the evidence does not support APS's claim that the proposed demand charges better reflect cost causation. I also find that current demand charge residential customers demonstrate low levels of engagement, understanding, and even awareness of the demand charge. Mandatory demand charges are unprecedented for state-regulated utilities and only limited examples exist of mandatory demand charges for electric cooperatives. In addition, a review of the academic literature reveals no support for the contention that residential customers are able to respond to the price signals presented by mandatory demand charge-based rates. This evidence belies APS's purported basis for mandatory demand charges. Moreover, my review of expected bill impacts on residential customers resulting from APS's proposed demand charges shows that the proposal would create disparate, and in many cases extreme, bill impacts, especially on customers investing in rooftop solar. Based on this evidence, I conclude that mandatory demand charges for residential and extra small commercial customers are not in the public interest and should be rejected by this Commission.

In light of the findings that no solar cost shift exists, that current solar customers produce a $60 million net benefit to other customers, and that mandatory demand charges are not in the public interest, I evaluate APS's proposal that customers investing in DG after the grandfathering deadline be restricted to rate schedule R-3—the proposed residential rate with the highest demand charge and lowest volumetric charge. Based on an APS study of residential customer load shapes, I find that solar customers do not have sufficiently different load characteristics to warrant differential rate treatment. Indeed, larger groups of customers with highly varying load shapes exist within the residential class.

I also review cost recovery from various solar customers relative to non-solar residential customers and other residential subgroups, including seasonal customers, apartment dwellers, and customers with natural gas service in their homes. This evidence demonstrates that while minor cross-subsidization exists, there is no significant cost shifting within the residential class under current rate design. In addition, I confirm my findings that solar customers recover more than their fair share of costs relative to other subgroups of residential customers. As a result, I recommend that the Commission find that APS's proposal to restrict rate options available to solar customers is not based on the evidence and would be discriminatory.

Taking into account the analyses and evidence reviewed in this case I recommend the following rate design be approved in this case.

- Existing DG customers should be grandfathered onto retail rate net metering and current rate design options.
- Additional restrictions should not be placed on the modified net metering rider and APS's proposal to restrict enrollment on Rider EPR-6S to systems less than 100 kW should be rejected.
- Existing residential and extra small commercial rate options should be maintained.
- Basic service charges for residential and extra small commercial customers should not be increased.
- The peak period should be redefined as 2 p.m. to 7 p.m.
- DG customers should be afforded the same rate options as other residential customers.
- DG customers who sign up for interconnection after the grandfathering deadline should not be subject to Rate Rider LFCR-DG.
- DG customers who sign up for interconnection after the grandfathering deadline should be charged a monthly meter fee of $4.26. In lieu of the monthly fee, customers should have the option to pay a one-time upfront charge of $296.91.
- The LFCR structure should not be modified at this time.

3 APS's Proposed Residential and Extra Small Commercial Rate Design Changes

Q. Please summarize APS's proposals for modification to residential rate design.

A. APS proposes to overhaul its residential rate offerings. APS currently offers residential customers their choice of (1) E-12: a non-time-differentiated inclining block rate; (2) ET-2: a time-differentiated two-part rate; (3) ECT-2: a time-differentiated three-part rate that includes a demand charge for the peak period; and (4) ET-SP: a time-differentiated two-part rate with a higher super peak period. APS's residential customers are currently free to choose any of the four rate options. Table 1 below presents the number and proportion of residential customers currently enrolled in each of the four rate plans.

Table 1: Residential Customer Tariff Enrollment[1]

Rate Schedule	Number of Customers	Percent Enrolled
E-12	478,000	46%
ET-1, ET-2	447,000	43%
ECT-1, ECT-2	120,000	11%
ET-SP	2,000	0%
Total	1,047,000	100%

APS's application proposes replacing these four rate schedules with four new schedules and restricts customer choice between options.

Q. Please describe the four proposed rate schedules.

A. APS proposes three primary residential rate tariffs that include varying levels of fixed charges, time-differentiated energy charges, and a peak demand charge.

[1] CAM_WP01DR – Proof of Revenue.xlsx. Data in this table reflect customers with and without rooftop solar. The table excludes the 218 customers with electric vehicles who are enrolled on APS's ET-EV tariff.

These rates are called R-1, R-2, and R-3.[2] APS also proposes Schedule R-XS, which includes a basic service charge, a flat energy charge, and no demand charge.[3] Under APS's proposal, customers with DG will be restricted to a single rate option, Schedule R-3, and only customers with monthly usage below 600 kWh per month will be eligible to take service on Schedule R-XS.[4] Table 2 below summarizes APS's projected breakdown in non-solar customer enrollment under the proposed tariff options based on eligibility restrictions and estimated customer savings.

Table 2: Projected Residential Customer Tariff Enrollment[5]

Rate Schedule	Number of Customers	Enrollment Estimate
R-XS	289,000	29%
R-1	185,000	18%
R-2	280,000	28%
R-3	260,000	26%
Total	**1,014,000**	**100%**

APS projects that the 222,000 residential customers currently enrolled on the E-12 tariff (that does not include time differentiation nor demand charges) will be placed on tariffs with time differentiation and peak demand charges.[6] This constitutes 22% of APS's current residential class. An additional 387,000 customers currently taking service on the two-part time-of-use ("TOU") rates are expected to be enrolled in demand charge rates for the first time.[7] In total, APS's proposed rate redesign would result in over half a million APS customers—609,000—facing unfamiliar demand charges under the APS proposal.[8]

[2] Direct Test. of Charles A. Miessner 3:18-21 ("Miessner Direct").
[3] *Id.* 4:13-16.
[4] *Id.* 4:17-18.
[5] VS 1.16.
[6] *Id.*
[7] *Id.*
[8] *Id.*

Q. Please describe APS's proposals for modification to extra small commercial customer rate design.

A. APS proposes to impose mandatory demand charges on all extra small commercial customers. The extra small commercial class consists of 100,000 small business customers with peak demands below 20 kW.[9] Of these customers, the vast majority chose to take service on the E-32 XS tariff that includes a basic service charge and tiered volumetric rate. Roughly 250 customers, or 0.2%, elected service on the optional E-32TOU XS rate that includes tiered and time-differentiated volumetric charges.[10] All of these small business customers will face unfamiliar demand charges under APS's proposal.

Q. Has APS provided information regarding the rationale for its rate design proposals?

A. Yes. APS included a Long-Range Rate Plan with its Application that summarizes the objectives of APS's rate proposals as follows:

> 1. Modernizing rates to enable new technologies and reflect the continued value of the electricity delivery system;
>
> 2. Improving rate fairness among customers by aligning rates with the cost of service, minimizing/eliminating embedded subsidies;
>
> 3. Providing rate gradualism and bill stability for customers by managing overall rate levels and thoughtfully transitioning to new rate designs; and
>
> 4. Enhancing customer satisfaction by providing fewer but more meaningful rate choices and simplifying rate schedules and bill presentation.[11]

[9] Schedule E-32 XS, CAM_WP01DR.
[10] CAM_WP01DR.
[11] Attachment LRS-05DR at 2.

Q. Does APS's proposal accomplish the objectives described?

A. No, it does not. As I will demonstrate in detail in this testimony, APS's proposal not only falls short of accomplishing these goals, but is actually counterproductive to the stated goals:

> **1. Rate modernization to enable new technologies:** By reducing the types of rate options available to residential customers, APS's proposal will discourage adoption of many new technologies that aid in conservation and manage peak energy usage.
>
> **2. Improve fairness, align rates with cost, and eliminate embedded subsidies:** While APS continuously makes the claim that volumetric rates create significant cost shifts—specifically, a cost shift from solar customers to non-solar customers—the evidence belies that claim. In addition, there is no evidence that APS's proposed demand charges are better at reflecting the cost to serve residential customers than current rate structures.
>
> **3. Providing rate gradualism and bill stability:** The evidence in this case shows that APS's proposal to impose demand charges on over a half million residential customers unfamiliar with such charges will result in significant and unmanageable bill impacts for a large number of customers.
>
> **4. Enhancing customer satisfaction:** The record of the Unisource Electric ("UNSE") case and the experience of other utilities that have implemented mandatory demand charges clearly demonstrate that this rate design is unpopular with the public and very likely to increase customer dissatisfaction.

The remainder of my testimony will present evidence that demonstrates that APS's proposed rates fail each of the purported bases and will recommend better rate design to accomplish the goals outlined in APS's Long-Range Rate plan.

4 <u>There is no solar cost shift</u>

Q. How does APS frame increased rooftop solar penetration as part of their general case?

A. APS submitted a 32-page executive summary of their rate case with their Application. The executive summary contains a short introduction followed by a single page entitled "Framing the Issue"[12] devoted to APS's allegation that there is a significant cost shift associated with compensation for DG under retail rate net metering. To support this allegation, Mr. Snook offers a COSS that purports to show that solar customers on volumetric rates pay only 38% of the cost to serve them, compared to the overall residential class paying 86% of the cost to serve them.[13] Based on this difference, Mr. Snook claims that there will be a 20-year cost shift resulting from the current rate structure of over $1 billion.[14]

In addition, Ms. Lockwood characterizes the rate proposal as "critical,"[15] in part, because of the alleged cost shift APS attributes to rooftop solar customers. According to Ms. Lockwood:

> The subsidies include, but are not limited to, the cost shift inherent in NEM, and can be managed, and customers presently enjoying this subsidy can be "grandfathered." The ability to insulate these customers from significant changes through grandfathering will not last long, perhaps not even until the Company's next rate case unless significant progress is made now.[16]

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[12] Rate Review Executive Summary at 3.
[13] Direct Test. of Leland Snook 30:1-12 ("Snook Direct").
[14] *Id.* 31:6-10.
[15] Direct Test. of Barbara Lockwood 5:26-6:2 ("Lockwood Direct").
[16] Lockwood 21:2-7.

Q. Have you been able to evaluate the claims of cost shifts from customers with DG?

A. I have. APS's application is hyper-focused on DG solar and presents large-scale residential demand charges as the only possible solution. While APS repeatedly characterizes growth of rooftop solar in its territory as "explosive,"[17] residential DG remains at low levels of penetration in the service territory. At the end of the test year, only 3% of APS's residential customers had installed DG.[18]

I also reviewed APS's COSS and determined that APS's claim of significant cost shifts related to rooftop solar is based on deeply flawed assumptions. When these assumptions are corrected, the evidence shows that solar customers are paying more than their fair share of costs, resulting in rate savings for the entire residential class.

4.1 APS's COSS Methodology Is Flawed

Q. Please describe the assumptions in APS's COSS that you refer to as flawed.

A. There are three primary assumptions employed in the APS COSS that must be modified in order to provide an accurate assessment of cost recovery from solar customers relative to other residential customers: (1) APS improperly allocated costs to solar customers based on loads not actually served by APS ("total load"), but costs are incurred based only on loads served by APS ("delivered load"); (2) APS improperly allocated costs to the residential class based on NCP measured by tariff option, rather than the class NCP, thereby inaccurately measuring the impact residential customer subgroups have on cost causation; and (3) APS inflated customer costs attributable to solar customers.

[17] i.e. Rate Review Executive Summary p. 2, Lockwood 2:13.
[18] CAM_WP01DR

4.1.2 Costs must be allocated to all customers based on delivered load.

Q. Please describe the first assumption that you found to be flawed.

A. Mr. Snook uses a COSS based on embedded costs from test year 2015 to evaluate costs to serve APS's solar customers.[19] Mr. Snook describes the COSS as follows:

> A COSS is the fundamental tool for allocating a utility's costs among its customers based upon their responsibility for incurring such costs. It is foundational in developing appropriate pricing structures that align the rates customers pay for the services received with the customers who are driving the costs. This is often described as the "cost causation principle."[20]

To examine NEM customers specifically, APS grouped its existing NEM customers into two classes: NEM customers on "energy-based" or two-part rates (Schedules E-12, ET-1, and ET-2) and NEM customers on "demand-based" or three-part rates (Schedules ECT-1 and ECT-2).[21] APS allocated costs to these groups of customers based on the NEM customer's <u>entire</u> load at the customer's home, including not only the portion of the load served by APS-delivered energy that APS incurs costs to provide, but also the portion served by the energy the customer generated with his/her DG system as a result of private investment to produce the energy being used.[22] APS then applied what it terms "credits" to the NEM customers based on APS's assessment of the value of capacity and energy savings resulting from the customer's DG production.[23] Mr. Snook summarizes his discussion of this methodology by stating: "The result is that the COSS analysis only allocates capacity and energy costs to NEM customers based on what APS has to provide."[24] Mr. Snook adds: "This analytical approach also captures the cost of providing grid services for the rooftop solar customer's export

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[19] Snook Direct 20:10-12.
[20] *Id.* 19:13-17.
[21] *Id.* 24:24-27.
[22] *Id.* 25:1-4
[23] *Id.* 25:21-23.
[24] *Id.* 25:23-24.

of energy and backup of the customer's self-supplied generation, including support for the starting of motors."[25]

Q. Do you support this methodology?

A. I do not. In APS's own words, the COSS is designed to "align the rates customers pay for the services received."[26] However, allocating costs to DG customers based on their total site load does not align with the services received from the utility. DG customers' site loads are served only partially by their utility, with their DG systems serving some portion of their loads as well. It is inappropriate to allocate utility costs to solar customers based on services the utility did not provide. The only appropriate basis for allocating costs in the COSS is allocation based on the services provided by the utility, which for all customers, with and without onsite DG, is delivered load.

Reaching behind the meter and allocating DG customer costs based on total site load (regardless of whether a portion of the load is met by self-generation) is equivalent to allocating costs to a customer for the energy they *would have* consumed from the utility had they not installed energy-efficient windows; or the energy they *would have* consumed had their kids not gone off to college; or the energy they *would have* consumed if they were year-round, rather than seasonal, residents.[27] When a customer chooses to install new technology or undergoes a lifestyle change that affects their energy consumption, the services they require of their utility change. As a result, that customer's cost-causing usage patterns change.

Mr. Snook claims that NEM customers have "vastly different load characteristics, [that] warrant evaluating them as a separate sub-class."[28] He made a similar claim in the Value of DG docket, where he provided a figure depicting hourly energy

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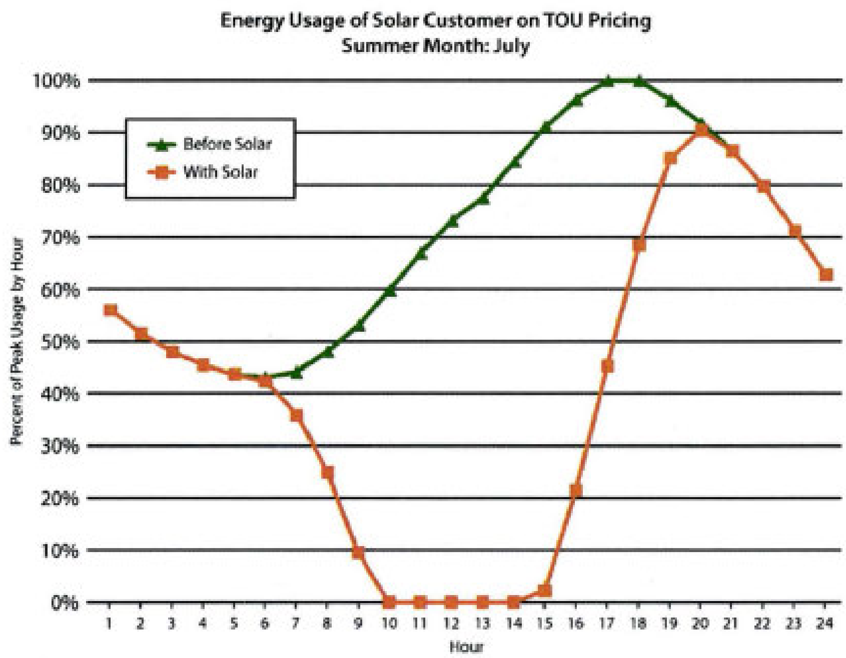
[25] *Id.* 25:24-26:2.
[26] Snook Direct 19:14-17.
[27] Notably, APS has not proposed to allocate costs to either of these types of customers based on what they do not consume.
[28] Snook Direct 24:17-19.

usage by a solar customer during July. That figure is copied below for illustrative purposes.

Figure 1: Figure from Mr. Snook's Direct Testimony in Docket No. 14-0023[29]



While Mr. Snook raised the "vastly different" profile as a reason to treat DG customers differently, the corollary is that APS incurs different costs to serve the different load shape of DG customers. However, APS's methodology in this case would allocate costs to NEM customers based on the "Before Solar" load shape shown on the top of Figure 1—as if they were no different than non-DG customers—and then partially credit back limited values associated with DG production. APS claims this load difference drives the need for separate evaluation of DG customers in the COSS, but it obfuscates this difference in the COSS analysis. The only way to actually capture the different load characteristics of DG customers, and therefore the cost to provide service, in the COSS is to examine the cost to serve those customers based on their delivered load. Delivered load is depicted as the "With Solar" load shape on the bottom of Figure 1.

[29] Snook Direct in 14-0023, 13, fig. 2.

Q. Has the Commission provided any guidance on this topic?

A. In part. The question of whether to examine all DG production, or to have the analysis focus on exported generation, was discussed at length in the Value of DG docket.[30] Decision 75859 expressed the agreement between Vote Solar and Commission Staff that "what a customer chooses to do behind the meter is the customer's concern and that the customer's right to reduce its load by the installation of a DG meter is no different from the customer's right to reduce load by conservation, insulation, high efficiency appliances, or storage."[31] Based on this description of the positions of Vote Solar and Staff, the Commission stated:

> For the reasons voiced by Vote Solar and Staff, the methodology we adopt will be used for the purpose of ascertaining the appropriate level of compensation to be paid to rooftop solar customers for their exported energy, and not for the purpose of determining a monetary value of the energy a DG customer consumes on site.[32]

For the same reasons that the Commission and utility should not reach behind the meter to value DG production for purposes of credits to DG customers, the Commission and utility should not reach behind the meter to assign costs and charge customers for what DG customers produce and consume onsite as a result of their private investments.

Q. What about APS's claim that allocation based on site load and then crediting back energy and capacity values captures the cost of grid services for solar exports and the costs to backup the customer's self-supplied generation?

A. There are two pieces to this claim. First, it assumes a need to capture grid services associated with exported generation in the rates charged for electricity the utility provides. Second, it refers to backup of self-supply.

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[30] Docket No. 14-0023.
[31] D.75859, 147:13-16.
[32] *Id.* at 147:18-21.

Regarding the first issue, APS's Application was developed prior to the issuance of Decision 75859, which has significantly changed the way in which exported DG will be handled in ratemaking. In Decision 75859 the Commission determined that retail rate net metering should be eliminated and replaced with a mechanism for direct purchase by utilities of DG exports and that the value of DG exports would be used to inform the compensation rates paid to DG customers for their exports.[33] While APS developed the COSS based on current rates and embedded costs, the results of that study are intended to inform rate design policy for future solar customers. With Decision 75859, the Commission decided that compensation for solar exports will include consideration of the cost of grid services to support solar exports, effectively collecting the cost of these services through reduced payments to customers for exported energy.[34] The same grid services should not also be included in the COSS as costs to be collected again from solar customers through rates for utility-provided service.

The second issue, recovery of costs associated with backup of customer self-supply, is already captured within a COSS that allocates based on delivered load. While APS characterizes solar customers as needing distinctive backup service,[35] there are no distinct services provided to a DG customer that are not provided to a non-DG customer except for the off-take of exported solar generation. Moreover, there is no analysis to support the conclusion that the results from APS's total load cost allocation minus credits formula represents the cost to provide the backup service to which APS alludes. Indeed, when asked in discovery, APS indicated that costs associated with this "backup service" are not even tracked.[36]

In testimony APS calls outs "support for the starting of motors" as emblematic of this backup service.[37] This service for supporting motor startup surge current, often referred to as inrush current, is supplied to customers with and without DG.

[33] D.75859, 169:27-170:5.
[34] D. 75859, Exhibit A.
[35] VS 5.20a
[36] VS 5.19c
[37] Snook Direct 25:24-26:2.

While APS is correct that solar customer inrush current requirements are not reduced in proportion to their reduction in energy requirements, the COSS already captures this issue through its widely accepted allocation factors. While inrush current is a service, in the most literal sense, it is provided by the whole of the grid system that is already allocated to customers. It is not true that everything upstream of the customer, including power plants and transmission lines, must be designed to handle simultaneous inrush current needs for all customers on the system. Indeed, the further you move from the customer, the greater the ability for capacity sharing due to load diversity, which in turn reduces the amount of infrastructure to provide service for dispersed customers. Accepted COSS methodologies, such as the methodologies employed in this case for non-solar customers, capture this phenomenon. Costs for production and transmission are generally allocated based on measures of coincident system peak, costs associated with the primary system and distribution substations are allocated based on the more specific class NCP, and costs for the portion of the system closest to the customer— distribution transformers, secondary lines, and services—are allocated based on the sum of individual customer peaks.

As a result of capacity sharing, it is really only the secondary system that must capture these short-duration customer requirements in its design criteria. In the COSS these costs are allocated based on the sum of individual customer peak demands.[38] The sum of individual peak demands for solar customers will not be significantly different whether measured based on site load or delivered load. That is, the diversity of customer loads, including inrush requirements, is already captured in the allocation methods used in the COSS and DG customers are allocated their shared of those costs through existing allocation factors. Superimposing inrush current costs on top of diversity-based allocation double counts costs.

APS's own methodology acknowledges that the COSS should recognize the reduced costs to serve DG customers by applying "credits" for the difference

[38] Snook Direct 23:23-26.

between delivered load and site load.[39] While APS acknowledges the need to recognize the difference in cost to serve, APS's methodology and unreasonable assumptions for doing so bears no relationship to the costs to serve DG customers. In addition, it is inconsistent with how APS allocates costs to all other customers. For example, APS applies an 8.13% rate of return[40] when calculating costs for services the utility provides, but only a 2.7% return[41] when calculating the credits applied for DG. Using differing rates of return for the costs and credits deflates the value of the credits relative to the costs attributed for the same service.

When asked in discovery to "provide all evidence, including each cost study, regression analysis, and any other information that you contend supports the assertions that there is a distinct cost to provide grid services and that the analytical [approach] proposed by Mr. Snook correctly calculates any such cost," APS was unable to provide any such evidence and simply stated that Mr. Snook's approach was appropriate.[42] Such an assertion is incorrect. It also lacks any evidentiary or empirical basis. Allocating costs to solar customers based on the total site load and then applying credits for the difference between site load and delivered load constructed from different rates of return for the same service bears no relationship to the "backup service" costs APS purports to capture. Indeed, APS admits not having quantified these costs to begin with. APS should be instructed to allocate costs to all customers on an equivalent basis, according to their delivered load. Any costs associated with so-called "backup service" should be directly quantified and allocated, rather than accepting APS's assumption that the difference between its cost allocation to total load and its calculation of so-called "credits" equals the cost of backup service for each DG customer.

[39] *Id.* 25:5-19.
[40] In the calculation of cost to serve solar customers based on site load, APS employed an 8.13% rate of return, the same assumption that was adopted for all other customers in the cost of service study. VS 5.22a.
[41] To calculate solar credits based on the difference between site load and delivered load, APS employed an assumed rate of return of only 2.7% based on APS's assessment of the rate of return from solar customers in the test year and includes the compensation solar customers received for exported generation under retail rate net metering. VS 5.22a.
[42] VS 5.19a.

Q. What do you propose for solar customer cost allocation?

I recommend that APS treat solar customers the same as all other customers in their COSS and employ standard COSS allocation methods based on their delivered load. APS presents an embedded COSS providing a historical snapshot of utility costs. APS additionally presents a methodology for allocating those costs to its customers based on a number of standard measures (i.e., energy-related costs are allocated based on kilowatt-hour ("kWh") consumption, distribution and generation capacity costs are allocated based on various measures of peak demand, etc.). This method is widely accepted and may be used to capture the cost to serve groups of customers based on the allocation methods contained therein. Evaluating solar customer costs with the same method—based on delivered load—appropriately captures the cost to serve these customers.

Q. How does your recommended COSS methodology address costs associated with energy exports?

A. It does not. Based on Decision 75859, my recommended methodology separates self-consumed DG from DG exports. I recommend that the Commission ensure that customers who choose to install DG or any other technologies that modify their consumption of utility-delivered energy be treated the same regarding cost of service allocation as their next-door neighbors who have not installed such technologies. Rates that solar customers pay for energy deliveries from the utility should be based on standard cost-of-service principles applied in an equivalent manner to all other utility ratepayers.

My recommendations are also consistent with APS's own statements in Docket No. 14-0023 that "compensation to a solar customer for net energy exported to the grid is distinct from the design of that customer's rate as established through a COSS."[43] My recommendations are also consistent with APS's statement that "[a] valid Value of Solar study is a resource planning exercise and should not be

[43] Snook Direct (Docket No. 14-0023) 28:22-24.

conflated with a cost-of-service analysis used for ratemaking."[44] However, APS's proposed methodology nevertheless conflates the two. Rather than "[u]sing a COSS to set rates [to protect] customers by ensuring that customers pay only for actual costs that they cause,"[45] APS's COSS here attempts to allocate costs and collect payment from DG customers for services not provided by the utility, but provided by the customer through her private investment.

What truly differentiates customers with DG from other customers is the DG customers' ability to export energy to the grid. That difference was already addressed by Decision 75859, in which the Commission ordered that exports be evaluated separate from self-consumption.

4.1.3 The residential class peak used for cost allocation should not be separated by tariff option

Q. Please describe the second flawed assumption that you found.

A. APS advocates allocating costs related to distribution substations and the primary distribution system based on the NCP of various customer groups.[46] In support of this assumption, Mr. Snook states: "[d]istribution plant, unlike production and transmission plant, is generally designed to meet a customer class's peak load, which may or may not be coincident with the system peak load."[47] While I agree with these statements, they do not reflect the methodology used in the actual COSS analysis conducted by APS. Rather than allocate costs associated with distribution substations and the primary distribution system based on a customer *class's* peak load, APS allocated costs for the residential class on different NCPs for *each tariff option*. In other words, APS used a different NCP for non-solar

[44] *Id.* 30:18-20.
[45] *Id.* 29:10-11.
[46] Snook Direct 23:22-23.
[47] *Id.* 23:20-22.

customers on rate schedule ECT-2 from the NCP used for non-solar customers on rate schedule ECT-1, ET-1, ET-2, E-12, etc.[48]

There is no evidence that distribution plant is designed for, and costs are driven by, the NCP specific to residential customer tariff options. The rationale behind allocating distribution substation and primary distribution line costs based on class NCP is that customers within a large class (e.g., residential customers) tend to be co-located on the distribution system so their combined peak load represents the peak loading on distribution plant equipment used to serve them. However, the same rationale does not hold for smaller sub-classes because there is significant diversity in consumption patterns for subgroups of customers served from a given substation and customers in subclasses are dispersed among many different substations that predominantly serve customers in other tariff groups. Put another way, a substation serving a mix of residential customers on different tariff options is not designed to accommodate the sum of every customer's individual peak demand, nor the sum of each tariff sub-group's peak demand. Rather, considerable capacity sharing is possible, as described in the NARUC Cost Allocation manual: "The load diversity at distribution substations and primary feeders is usually high. For this reason, customer-class peaks are normally used for the allocation of these facilities."[49]

The NARUC manual recognizes that distribution planners design substations and primary distribution lines based on the expected peak of the diverse group of customers served by that portion of the system. To represent this in a COSS allocation, it is common practice to use the class NCP. It is not common practice to differentiate NCPs by residential tariff option, as APS does, because there is likely little to no correlation between the substation and primary feeder serving a given customer and that customer's choice of which optional rate offering to choose. APS certainly has not provided evidence of any such correlation in the record.

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[48] VS 3.10.
[49] NARUC Cost Allocation Manual 1992, p. 97.

Q. Have you measured the impact of APS's choice to use separate NCP by tariff option on the COSS results?

A. I have. Through discovery I was able to determine that the entire residential class reached its class peak in the test year on August 15th at 5 p.m.[50] That same hour happened to coincide with the overall system peak, often referred to as the 1CP.[51] In contrast, APS's COSS used tariff option-specific NCP's as allocators, resulting in over-allocation of costs to the residential class as a whole and to DG customers in particular. Table 3 below presents the timing of each tariff option NCP as used in the APS COSS and indicates the resulting over-allocation to each group of customers relative to if APS has instead chosen to use the residential class peak.

Table 3: Tariff Option NCP and Over-Allocation in COSS[52]

Tariff Option	Subclass Peak	Over-Allocation
No Solar		
E-12	8/16/15 17:00	2%
ECT-1R	8/15/15 17:00*	0%
ECT-2	8/15/15 17:00*	0%
ET-1	8/15/15 17:00*	0%
ET-2	8/15/15 17:00*	0%
ET-SP	8/16/15 18:00	2%
Solar		
E-12	8/16/15 20:00	51%
ECT-1R	8/16/15 20:00	39%
ECT-2	8/16/15 20:00	35%
ET-1	8/15/15 19:00	41%
ET-2	8/16/15 20:00	41%

As shown in Table 3, the subgroups of non-solar customers on all but the E-12 and ET-SP tariff reached their tariff-specific NCP on August 15, 2015 at 5 p.m., which is the same time that the residential class reached its peak. Because the

[50] VS 6.6.
[51] Pre-filed 1.40 APSRC00530.
[52] VS 6.6, VS 3.10, VS 8.1; pre-filed 1.40 APSRC00530. Asterisk indicates subgroup NCP hour is the same as class NCP.

class and sub-class NCP coincide for these sub-classes, APS's allocation based on sub-class NCP does not impact the results for these customers. In contrast, all of the solar customers reached their tariff option peak at different times. Most solar customer sub-groups peaked on an entirely different day and all solar customer sub-groups reached their peak hours after the class and system peak.

There is no evidence that sub-class NCP allocation is cost based. Solar sub-classes are not served by dedicated substations and primary lines, which is what the COSS effectively assumes. A single substation or primary feeder may serve a mix of residential sub-classes but does not have multiple separate peaks. Using sub-class NCP is therefore irrational and not supported by any evidence and results in allocations to DG customers that are 35-50% too high.

Using sub-class NCP also undermines effective price signals embedded in rates. For example, APS provides a tariff option ET-SP that includes volumetric rates as high as $0.46/kWh during the summer super peak period of 3 p.m. to 6 p.m.[53] This rate should send a price signal to shift use away from those hours, and should give customers opting for that tariff proportionately reduced rates for their shift in peak use. As of the test year, 1,559 customers chose this rate option.[54] According to APS's data, the residential class reached its test year peak at 5 p.m. on August 15th, 2015. In contrast, the small group of customers taking service on the ET-SP super peak tariff reached their group peak on an altogether different day and at a later hour, presumably incented by the price signal in their tariff to shift peak demand outside of the super peak period[55] Rather than recognize that ET-SP customers responded to a price signal to shift peak and allocate the reduction in costs to those customers accordingly, APS allocated costs to this small group of customers based on their peak demand as a small subgroup, which recognizes no distribution demand cost reduction value for their collective shift of use away from peak.

[53] Schedule ET-SP.
[54] CAM_WP01DR – Proof of Revenue.xlsx.
[55] VS 3.10.

Similarly, APS's separate NCP provides no recognition to solar customers for self-supply during distribution system peak and that reduces loading on the distribution system. Electric cooling on hot summer afternoons drives peak residential loads in Arizona. At those same times, even if lower than maximum production, solar DG still produces significant levels of output, allowing customers with DG to lower their contribution to peak loading on the distribution system. Indeed, the evidence from APS's 2015 test year demonstrates that the subgroups of solar customers were able to reduce their relative demand significantly at the time when it was needed most on the APS distribution system. As shown in Table 4, solar customer loading on the system was reduced by 35-41% on August 15, 2015 at 5 p.m.

Table 4: Solar customer load reduction at time of residential NCP[56]

Customer Group	Site Load	Delivered Load	Solar Peak Load Reduction
Solar Customers on Energy Rates	185 MW	109 MW	41%
Solar Customers on Demand Rates	10 MW	6.5 MW	35%

The COSS should recognize reduced loading at peak and reward customers for responding to price signals to do so. DG customers reduced their loading during the relevant test year peak load periods on the distribution system. They should see a proportionately reduced cost allocation as a result. However, inappropriate cost allocation using different sub-class peaks, rather than the peak loading on distribution equipment, no longer connects cost allocation to cost causation and thus skews results and undermines the purpose of the COSS exercise, which in APS's own words is to "develop[] appropriate pricing structures that align the rates customers pay for the services received with the customers who are driving the costs."[57]

[56] Pre-filed 1.40 APSRC00530.
[57] Snook Direct 19:14-16.

Q. **How do you propose modifying APS's COSS to allocate costs to the residential class?**

A. I recommend that the Commission instruct APS to revise the COSS analysis to allocate distribution plant to the residential class peak, not to individual tariff groups. That change would be consistent with APS's own testimony that "[d]istribution plant … is generally designed to meet a customer class's peak load."[58]

4.1.4 The COSS should treat residential customers with and without solar the same in terms of customer-related costs. Any differences should be accounted for through a DG meter fee.

Q. **Please describe the third assumption that you found to be flawed.**

A. When a customer installs DG she requires different metering equipment. APS will replace the standard residential meter with a bi-directional billing meter and will also install a production meter. The bi-directional billing meter handles all billing functions for the DG customer and is required for measurement of exported generation. The production meter is used by the utility to measure total solar output for RES compliance purposes. The Commission initiated installation of production meters with approval of APS's 2012 REST Implementation plan for the express purpose of ensuring that solar PV systems that received upfront incentives were performing as expected.[59] Since approval, capital and installation costs associated with the production meters have been tracked and recovered in the REST and passed on to customers through the Renewable Energy Standard rate rider, of which DG customers are required to pay the maximum amount.[60]

[58] *Id.* 23:20-22.
[59] D.72737 in 11-0264, 9:13-16.
[60] Rider REAC-1.

Q. Has the Commission provided any guidance on this issue?

A. Yes. APS proposes to include the costs associated with bi-directional meters and solar production meters in the COSS and has allocated these costs, with a number of significant loading factors, to solar customers. A similar proposal was addressed in the recent TEP case where the utility proposed a meter fee to capture: (1) production meter costs and (2) loading factors on customer costs in excess of the incremental capital and labor costs associated with installation of the bi-directional meter.[61]

Regarding the first issue, TEP argued that production meter costs would not be incurred but for residential DG installation.[62] The ALJ's Recommended Order and Opinion found that "[t]he production meter supports REST compliance (and LFCR calculations). The REST Rules are for the benefit of all ratepayers, the Company, and society in general, and the cost of REST compliance should not be imposed only on the group of customers who contribute to meeting renewable goals."[63]

Regarding the inclusion of loading factors on meter costs in excess of the incremental capital and labor costs associated with installation of the bi-directional meter, TEP's proposal assumed that the loading factors for solar customers should be twice the loading factors for non-solar customers.[64] The ALJ's Recommended Order and Opinion found the evidence supported a meter fee limited to the incremental capital and labor cost to install a bi-directional meter, and rejected TEP's proposal to include loading factors.[65]

[61] Recommended Order and Opinion (Docket No. 15-0239), 154:10-15 ("ROO").
[62] *Id.* 154:15-17
[63] *Id.* 154:24-155:1
[64] *Id.* 151:14-16
[65] *Id.* 155:5-8

Q. What do you recommend for allocation of meter costs to DG customers in this case?

A. I recommend that the COSS be revised to treat residential customers with and without solar the same when allocating customer-related costs and loading factors. Consistent with the ALJ's Recommended Order and Opinion in the TEP case, the incremental capital and labor costs associated with solar customers' bi-directional meters should be captured through a meter fee. I propose such a meter fee in Section 7.7 below and incorporated the estimated incremental costs associated with bi-directional meters in my analysis.

4.2 A corrected analysis shows solar customers pay more than their fair share of costs under the current rate design

Q. Were you able to conduct an analysis that incorporates your recommended adjustments?

A. Yes. I developed an analysis that incorporates the three changes recommended above. Specifically, I (1) allocate costs to DG customers based on the load actually being served by the utility at the utility's cost (delivered load), rather than what the customer is serving herself at her own cost; (2) use the residential class NCP, rather than the peak for each individual tariff option within a class; and (3) treat all residential customers the same in terms of customer-related costs and loading factors with the exception of incorporating the incremental costs associated with bidirectional meters as a solar customer-specific cost.

Q. Please describe the steps you took to conduct your analysis.

A. My analysis was developed based on a method employed by APS in the Value of DG Docket.[66] Beginning with APS's assessment of the total residential class revenue requirement functionalized for various cost categories—production, transmission, distribution, etc.—I developed an assessment of relative cost

[66] *See generally* Docket No. 14-0023.

recovery from APS's residential customers with and without DG. By beginning the analysis with APS's assessment of the total residential class revenue requirement, my analysis results in a slight underestimate of cost recovery from all subgroups of customers. This is because full integration of the assumptions described above would lower the overall residential revenue requirement. Because the majority of the cost savings anticipated would accrue to solar customers, and solar customers make up a very small proportion of the residential class as a whole, I do not expect this approximation to have a material impact on the results.

To analyze relative cost recovery from residential customers on different tariff options, I unitized each category of costs based on the total residential allocator for the cost category consistent with the allocation factors employed in the COSS. For example, costs associated with transmission were unitized and allocated based on the four coincident peak ("4CP") allocation factors, costs associates with distribution substations were unitized and allocated based on the NCP allocation factors, etc. All allocation factors were developed based on delivered load and NCP was adjusted to account for the residential class NCP as described above, as opposed to APS's method by which tariff-option-specific NCP was employed. This information was provided by APS in discovery.[67]

One allocation factor employed in the COSS, Average and Excess Demand ("AED") for Production Demand costs, does not lend itself well to this analysis. In this case I elected to replace the AED allocator with an average of the 4CP and the class NCP. This is consistent with the methodology employed by APS in developing its solar credit factors, which APS describes as "consistent conceptually with the AED method, which uses both the coincident and NCPs to allocate production demand costs"[68]

In APS's COSS analysis, revenues from a subclass were compared to APS's assessment of the cost to serve the customers in that subclass. In the calculation of

[67] Pre-filed 1.40 APSRC00530.
[68] VS 5.23.

revenues from solar customers, APS subtracted compensation at retail rate through net metering from the revenues received. Decision 75859 concluded that retail rate net metering should be replaced by utility direct purchase of DG exports and that the export rates be set based on the value of the DG exports to the utility.[69] Decision 75859 separates DG customer electricity flows into two distinct transactions: utility sales to the customer, and customer sales to the utility at value-of-DG-based rates. As a result, my methodology evaluates the first transaction—rates for service provided to DG customers—not the DG export compensation. Therefore, it should exclude the export energy transactions. Those transactions will be evaluated in a separated study. To evaluate rates for services provided to DG customers, I analyzed the revenues received from DG customers in the test year by separating what customers paid for delivered load from the compensation received under retail rate net metering using a census of hourly DG customer usage data provided by APS.[70] A comparison of these revenues to the subclass costs provides an assessment of relative cost recovery from solar customers under current rate design.

Q. What were the results of your analysis?

A. My analysis demonstrates that DG customers pay rates covering a higher level of the costs to serve them when compared to other groups of residential customers. This means that there is no cost shift from solar customers to other residential customers from the current rate design.

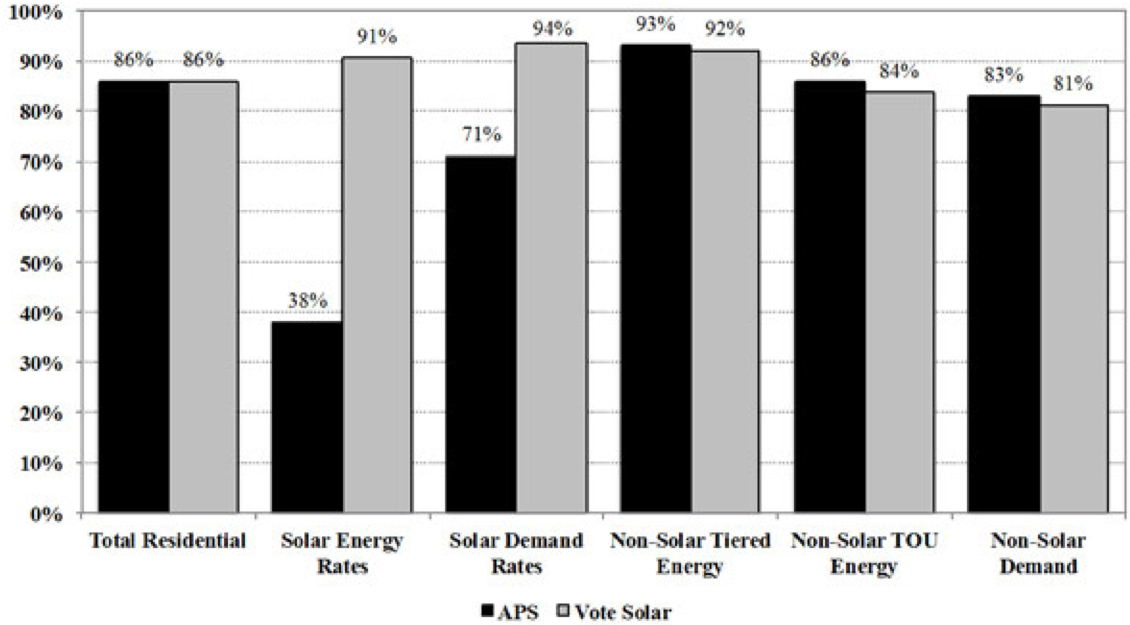
APS's cost shift allegations are based on Mr. Snook's assertion that DG customers on energy-based tariffs pay rates covering only 38% of the cost to serve them and DG customers on demand tariffs pay rates covering only 71% of the cost to serve them, rather than the residential class average of 86%.[71] Those calculations, however, are based on the COSS that includes the flawed assumptions described above. That is, it assumes utility costs accrue due to loads

[69] D.75859, 169:27-170:5.
[70] VS 1.4, 1.5, and 1.6.
[71] Snook Direct 30:1-12, LRS_WP06DR.

that the DG customer is self-serving, allocates costs to peaks by tariff group rather than class, does not separate DG customers into the separate buy and sell transactions required by Decision 75859, and inappropriately allocates production meter costs and loading factors to solar customers. In contrast, my revised analysis shows that under current rate design, DG customers on energy rates pay 91% of the cost to serve them, and DG customers on demand rates pay 94% of the cost to serve them. This exceeds the cost recovery from the total residential class of 86%.

Notably, at 91% and 94%, DG customers pay a higher percentage of the costs to serve them than do APS's non-DG customers who take service on demand rates. These customers are found to pay only 81% of the cost to serve them. These results are summarized in Figure 2 below. This is especially significant since APS points to demand rates for all residential customers as a way to increase the amount of costs recovered from those customers.

Figure 2: Comparison of APS and Vote Solar Residential Cost Recovery Results[72]



It is clear from the results provided in Figure 2 that APS's COSS skews in ways that disfavor DG customers. When costs are allocated to DG customers on the same basis as costs are allocated to all other customers and when class peak assumptions are revised to reflect the way costs are actually incurred, APS's allegations about significant cost shifting by DG customers evaporate. Indeed, while APS found that DG customers on energy rates and demand rates underpay by approximately $72 and $28 per month, respectively,[73] a revision to APS's analysis based on the corrected analysis reveals the opposite. If rate design is kept the same but APS received its requested base rate increase, DG customers on both energy and demand rates are expected to overpay relative to the non-solar residential class average with DG customers on energy rates overpaying by $7 per month and DG customers on demand rates overpaying by $17 per month. These results are summarized in Table 5 below.

[72] APS figures from LRS-4DR.
[73] Snook Direct30:17-19.

Table 5: Comparison of APS and Vote Solar Estimation of Solar Customer Cost Collection Relative to Non-Solar Residential Customers under Current Rate Design

	APS[74]	Vote Solar
Solar Energy Rates	-$72.00	+$7.00
Solar Demand Rates	-$28.00	+$17.00

Q. How do your results impact APS's claim that grandfathered solar customers will shift over $1 billion to other customers over twenty years?

A. My results cannot be extrapolated in the same manner that APS extrapolated its results because my results relate only to rate design and APS's results capture their assessment of export compensation for grandfathered customers under retail rate net metering. However, even with conservative assumptions regarding the costs and benefits of energy exports, it is clear that current solar customers who take service under retail rate net metering provide a net benefit to other residential customers.

For a conservative proxy (i.e., which significantly undervalues solar exports), I used the value of DG described in Decision 75859 as Staff's value from the Resource Comparison Proxy prior to inclusion of distribution, transmission and line loss adders: $0.109/kWh.[75] Using this conservative assumption for the value of solar exports, APS's test year shortfall is $8 per month from DG customers on energy rates and an over-recovery of $22 per month from DG customers on demand rates. In addition to the $7 per month that solar customers on grandfathered energy rates are overpaying with current rate design, grandfathered customers are subject to an additional fixed charge of $0.70/month per installed kW for their DG system under Rider LFCR-DG. This adds up to an additional $4 per month per customer. Added to the $7-$17 per month that solar customers on grandfathered rates overpay with current rate design, it is again apparent that no shift exists from solar DG customers to other customers, even for the customers

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[74] *Id.*
[75] D.75859, 116:14-15.

that APS has proposed to grandfather under retail rate net metering. If anything, costs are shifted from other customers onto solar DG customers, who pay for the DG systems that provide net positive benefits to the utility. These results are summarized in Table 6 below.

Table 6: Estimated Monthly Net Benefits from Grandfathered Solar Customers

	Energy Rates	**Demand Rates**
Rate Design	$7.00	$17.00
Export Compensation[76]	-$8.00	$22.00
Capacity Charge	$4.00	-
Total	**$3.00**	**$39.00**

Extrapolating these results over twenty years in a manner consistent with APS's analysis reveals that rather than a $1 billion cost shift from solar DG to other customers, as alleged by APS, conservative assumptions show a net benefit of $60 million to non-solar customers resulting from APS's grandfathered solar customers.

5 Mandatory demand charges for residential and small business customers are not in the public interest

Q. Please provide a summary of the residential and small business demand charge proposals put forth in this proceeding.

A. APS proposes significant changes to the rate design for residential customers, including automatic enrollment of a majority of their customers on rates that include demand charges and time-varying volumetric charges. Currently only about 11% of APS's residential customers choose to take service on the optional demand-charge tariffs ECT-1 and ECT-2.[77] Based on APS's analysis, APS's

[76] Based on an assumption that the value of DG is $0.109/kWh. Vote Solar does not endorse this value but has employed this assumption in the interest of conservatism in this analysis.
[77] CAM_WP01DR – Proof of Revenue.xlsx.

proposal would impose rates with a demand charge on 72% of customers (all but the smallest residential customers).[78] A review of test year data used to develop enrollment projections reveals that 22% of APS's customers, roughly 222,000 individual households, will be moved from the tiered rate that does not include time differentiation nor demand charges and will be placed on demand charge rates.[79] Another 38% of APS's customers, roughly 387,000 individual households, will be moved from a volumetric TOU rate to a rate with a demand charge.[80] In total, this is more than a half-million APS customers—609,000 to be precise—that will face unfamiliar demand charges under the APS proposal.[81]

In addition, APS proposes adding demand charges for its extra small commercial customers. There are 100,000 of these small business customers, each with an average monthly demand of less than 20 kW.[82] Of these customers, the vast majority choose to take service on the E-32 XS tariff that includes a basic service charge and tiered volumetric rate. Roughly 250 customers, or 0.2% elected service on the optional E-32TOU XS rate that includes tiered and time-differentiated volumetric charges.[83] All of these small business customers will face unfamiliar demand charges under APS's proposal.

Q. Please describe the demand charges proposed in APS's Application.

A. For residential customers, APS proposes three demand-charge-based tariffs: R-1, R-2, and R-3. Each tariff would include a demand charge based on the customer's peak demand as measured over one hour during the proposed peak period of 3 p.m. to 8 p.m. on weekdays.[84] Schedule R-3 would differentiate the applicable demand charge by season while Schedules R-1 and R-2 would have the same

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[78] VS 1.16.
[79] *Id.*
[80] *Id.*
[81] *Id.*
[82] Schedule E-32 XS, CAM_WP01DR.
[83] *Id.*
[84] Miessner Direct 4:23-24.

demand charge all year.[85] A summary of the proposed three-part rates is provided in Table 7 below. APS proposes allowing non-DG customers to choose between rate options, but proposes to restrict DG customers to Schedule R-3, the schedule with the highest demand charges and lowest volumetric rates.[86]

Table 7: APS's Proposed Three-Part Residential Rates

Bundled Rates	**Unit**	**R-1**	**R-2**	**R-3**
Monthly Fixed Charge	$/Month	$24.00	$14.50	$24.00
Demand Charge				
Summer On-Peak	$/kW	$6.60	$8.40	$16.40
Winter On-Peak	$/kW	$6.60	$8.40	$11.50
Energy Charges				
Summer On-peak	$/kWh	$0.15160	$0.15160	$0.09090
Summer Off-peak	$/kWh	$0.08070	$0.08080	$0.05475
Winter On-peak	$/kWh	$0.12730	$0.12730	$0.06670
Winter Off-peak	$/kWh	$0.08070	$0.08080	$0.05475

APS describes Schedule R-1 as a revision to the current TOU energy rate, ET-2; and R-3 as based on the current demand charge rate, ECT-2.[87] However, a comparison to current ET-2 and ECT-2 rates demonstrates that there are significant differences. This is shown in Table 8 below.

[85] *Id.* 4:1-12.
[86] *Id.* 4:17-18.
[87] *Id.* 24:11-25:10.

Table 8: APS's Current TOU and Demand Rates

Bundled Rates	**Unit**	**ET-2**	**ECT-2**
Monthly Fixed Charge	$/Month	$16.91	$16.91
Demand Charge			
Summer On-Peak	$/kW	-	$13.50
Winter On-Peak	$/kW	-	$9.30
Energy Charges			
Summer On-peak	$/kWh	$0.24477	$0.08867
Summer Off-peak	$/kWh	$0.06118	$0.04417
Winter On-peak	$/kWh	$0.19847	$0.05747
Winter Off-peak	$/kWh	$0.06116	$0.04107

For APS's extra small business customers, APS proposes modifying Schedule E-32 XS and E-32TOU XS to add a demand charge of $4.30/kW for primary service customers and $6.90/kW for secondary service customers.[88] Like the proposed residential demand charges, APS proposes to measure the E-32 XS demand charges over one hour. However, unlike the proposed residential demand charges, APS proposes a NCP demand charge for E-32 XS.[89] This means that customers will be charged for their highest single hour demand at any time in the billing period regardless of whether that demand occurs during peak hours.

Q. What is APS's rationale for imposing mandatory demand charges on the majority of residential customers and extra small commercial customers?

A. Ms. Lockwood describes the proposed residential rate design changes as "critical" and states that the changes "will reduce intra-class subsidies, better reflect the cost of service, provide incentives for the deployment of new customer technologies and offer new rate and billing options."[90] She focuses the majority of her

[88] Proposed Schedule E-32 XS.
[89] *Id.*
[90] *Id.* 5:26-6:2.

discussion on the "cross-subsidization issue" and refers to Mr. Snook's findings regarding a solar cost shift.[91]

In Mr. Miessner's testimony he states that APS believes the existing two-part rate designs to be "economically inefficient, ineffective in reducing a utility's total costs to serve customers, and ultimately unfair."[92] He states:

> It is imperative that APS has new rate designs that:
> - Incent the technologies that reduce both demand and energy;
> - Provide accurate price signals for incenting how and when customers use electricity;
> - Reflect the types of services provided by the utility and the costs for those services; and,
> - Provide opportunities for customers to save on their bill without shifting costs to other customers.[93]

To justify imposing demand charges on E-32 XS customers, Mr. Miessner simply states that, "[s]imilar to residential rates, APS's current rates for extra-small general service customers are misaligned with the cost of service because most of the grid infrastructure investment costs are recovered through kWh energy charges."[94]

Mr. Snook claims that APS's proposal supports its long-range goals to (1) modernize rates to enable new technologies; (2) improve fairness, align rates with cost, and eliminate embedded subsidies; (3) provide rate gradualism and bill stability; and (4) enhance customer satisfaction.[95]

Q. Do you agree that APS's proposal will help accomplish these goals?

A. No. I strongly disagree that APS's proposal to impose mandatory demand charges for all but the smallest residential customers and to impose demand charges on extra small business customers will accomplish any of the stated long-range rate

[91] *Id.* 6:7-13.
[92] Miessner Direct 8:5-6.
[93] *Id.* 15:26-15:6.
[94] *Id.* 49:26-50:1.
[95] Snook Direct, LRS-05DR at 2.

plan goals. In fact, if approved, I expect APS's proposal to be counterproductive to the stated goals.

5.1 APS has not proven that demand charges improve the link between costs and rates

Q. Please describe the goal of cost-causation in rate making.

A. While there are a number of important goals to consider in ratemaking, APS's application focuses on the goal of providing rates that reflect costs. This goal is measured through a COSS process whereby costs are allocated to groups of customers based on proxy measures for how customers' consumption patterns contribute to those costs. Thus, the assessment of whether rates reflect costs depends in large part on whether the COSS correctly allocates costs to the correct proxy measures for how consumption patterns drive costs and whether the charges to customers are imposed on the same consumption patterns.

APS developed a number of allocation factors to approximate the cost-causing attributes of customer groups. These include: average and excess demand as a measure of production-related costs, annual energy usage as a measure of energy-related costs; 4CP demand as a measure of transmission-related costs, class and sub-class NCP demand as a measure of costs related to distribution transformers and the primary distribution system, and the sum of individual peak demand as a measure of costs related to the secondary distribution system.[96] In support of its proposal, APS claims that its proposed rates "will more closely match the cost of service with the monthly bill for each customer" using its cost-of-service analysis, and the cost allocation proxies and assumptions used in that analysis, as the measure.[97]

[96] *Id.* 22:12-23:27.
[97] Miessner Direct 36:24-25.

Q. Has APS provided any evidence to support its claim that mandatory demand charges for the majority of residential customers will more closely match the cost of service for each customer?

A. No. In fact, rather than basing their claim on analytical results, APS's case for demand charges appears to be based purely on the fact that the COSS allocates costs on demand-related measures, therefore in APS's view a rate that includes a demand charge must automatically provide a better match to those costs. The logic appears to be that (1) the cost allocation proxies in the COSS accurately assign specific costs to specific consumption patterns and (2) the demand charges APS proposes to impose will collect revenue for consumption patterns matching those used to assign costs in the COSS. When asked in discovery to provide analyses supporting this claim, APS replied:

> Because the costs for all customer classes are driven by a combination of demand-related costs, energy-related costs, and customer-related costs, APS's proposed revisions to residential rates, which include higher service charges, a much wider use of demand charges, and continued emphasis on time-of-use energy charges are much better aligned with the cost of service.
>
> The process is never perfect – it is not practical to have a cost of service study and rate for each home, or to identify and account for all cost differences in customer subgroups, or to develop a separate rate for each hour of the year for general rate offerings. Nevertheless, a set of rate options that is structured to reflect the major cost drivers, such as a three-part time-of-use demand rate will provide significant improvement for generally aligning customer bills with cost of service.[98]

While I agree that rate design is never perfect, APS's claim that it would be impractical to have a COSS and rate for each individual customer is a straw man. Nobody reasonably expects individualized cost-of-service studies. The question is whether the proposed rates collect revenues based on consumption patterns that match the consumption patterns that drive costs. Simply naming a consumption

[98] AURA 1.33.

attribute "demand" and then naming a charge a "demand charge" does not mean that the revenue collected through the "demand charge" is aligned with the consumption patterns that drive costs. Insisting on three-part rates because the COSS uses three general categories of cost allocation with similar sounding names—without regard to whether the revenues collected under the three-part rates would reflect the consumption patterns driving costs—puts form over substance. APS has failed to provide evidence in this case that the rates it proposes to impose through demand charges are aligned with the consumption patterns that drive costs.

Q. Are there other reasons to doubt that the proposed demand charge rates will better reflect cost when compared to the current residential rate offerings?

A. Absolutely. Cost causation is only one of the considerations for rate design. In addition, all rate designs must balance accuracy in price reflection with simplicity and understandability for the customer. In this case, APS proposes to impose demand charges on residential customers based on the highest hour of usage each billing month that occurs between 3 p.m. and 8 p.m. on non-holiday weekdays. This means that an individual customer will pay a demand charge each month based on a single hour in the roughly 108-hour peak period. Over the year the customer will be charged based on 12 hours of 1,300 contained in the peak period.

In contrast, APS's COSS has determined that the residential class causes costs based on demand during a small subset of those hours that were coincident with the four monthly summer peak hours and the subclass peak hour.[99] Because residential customers reached their class peak in the same hour as the August system peak, the majority of APS's demand-driven costs were based on consumption in only four hours of the test year.[100] There is no evidence of

[99] While APS's testimony states that costs for certain categories should be allocated based on the residential class peak, the cost of service study presented allocated costs based on a residential customer tariff option. This assumption has been revised in Vote Solar's cost of service study analysis.
[100] VS 6.6.

correlation between individual customer demand during any 12 of the 1300 "on-peak" hours in a year and those four cost-driving hours. Nor is there any evidence that demand rates for residential and very small businesses sends a price signal that customers can respond to in order to reduce demand during the four cost-driving hours. There is also no evidence that other tariff options that do not include a demand charge are less effective at sending price signals for the four critical hours to residential and very small business customers.

In fact, APS's proposed demand rates are not aligned with, and would not send a price signal for, the important cost-driving system peak hour. APS proposes to charge demand during a 3-8 p.m. weekday "on peak" period. However, the most consequential of the cost-causing hours in the test year—the August peak hour—occurred on a Saturday, outside of the peak period.[101] Because APS's COSS estimates that only three "on-peak" hours were relevant to costs in the test year it is possible and indeed likely that no connection may exist between an individual customer's billed demand and the estimated costs incurred to serve that customer.

Additionally, I note that once a customer hits his or her peak hour each month, demand in all other hours is effectively free. For example, if a customer on a peak-period demand rate had peak use at 3 p.m. on the first of August, she has little incentive to reduce demand during the rest of the month—including during the critical system peak hour.[102] The same customer, on a correctly designed TOU rate, has an incentive to reduce usage during all on-peak hours, even those after her monthly peak use hour.

While demand charges have long been used as a tool to reflect cost causation for larger commercial and industrial customers, the smaller individual size and

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[101] Johnson, Weldon. "August was 2nd hottest on record for Phoenix" *The Republic* (Aug. 31, 2015), http://www.azcentral.com/story/news/local/phoenix/2015/08/31/august-2nd-hottest-record-phoenix/71492942.

[102] APS has proposed to include time differentiation for the volumetric charges on its proposed demand charge rates, however, because the volumetric rate is reduced with the presence of the demand charge, the price signal from the volumetric charge is significantly dampened.

significant load diversity that exists among residential and small business customers must be taken into account. APS claims that "[t]he size of the grid necessary to serve the home is driven by the home's kW demand. This includes infrastructure investments in power plant capacity, wires, poles, substations, transformers, and other capital equipment."[103] However, as APS subsequently admitted in discovery, there is a difference between an individual customer's peak load and the cumulative peak load that drives system capacity such that system capacity needs will be less than the summation of individual customer peak demands.[104] In fact, APS's load data for the test year reveals that the sum of individual peak demand for the non-solar residential customers is roughly 50-120% higher than the measures of residential peaks that drive the majority of demand-related costs in the COSS.[105] For solar customers the difference is even more dramatic with individual peaks 100-160% higher than the measures of peak that drive the majority of demand-related costs in the COSS.[106]

Indeed, APS's own COSS found that of residential customers without DG, customers on demand charges paid a smaller percentage of the cost to serve them than customers on the other tariff options, and it was the customers on the standard tiered rate that recovered the largest percentage of their cost to serve in the test year.[107] That is, based on APS's own metric—its COSS—demand rates did a poorer job of aligning costs with revenues. This is shown in Figure 3.

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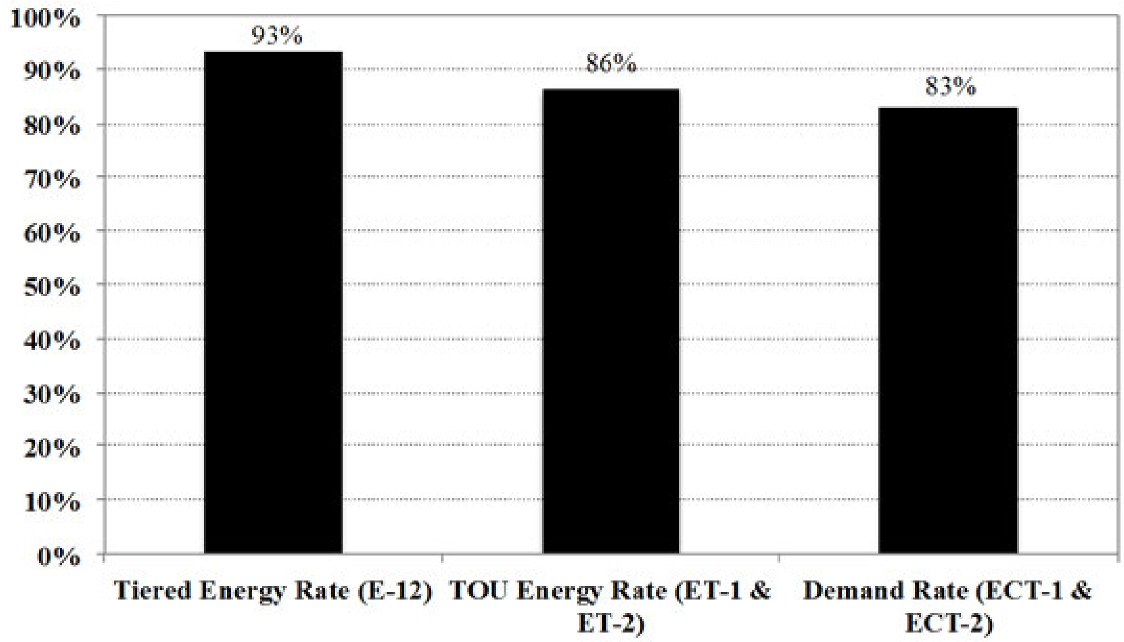
[103] Miessner Direct 17:3-5.
[104] VS 1.33.
[105] Pre-filed 1.40 APSRC00530.
[106] *Id*.
[107] Snook Direct 30:1-12.

Figure 3: Relative Cost Recovery from Residential Customers in APS COSS[108]



These findings also demonstrate that customers on the standard tiered energy rate, E-12, pay a higher percentage of the costs to serve them than the customers on the optional TOU and demand rates. This is contrary to APS's assertions that the existing two-part rate designs are "economically inefficient, ineffective in reducing a utility's total costs to serve customers, and ultimately unfair."[109] In addition, these findings are consistent with the Commission's determination in 1988 when Schedule E-12 was being evaluated in relation to declining block tariffs and optional demand charge rates: "Schedule E-12 … generally reflects the cause and effect relationship between the use of electricity for central refrigerated air-conditioning, the dramatic increase in the total system demand during the summer months, and the demand-related costs (as well as energy costs) incurred by APS to meet its summer peak."[110]

It is also unsurprising that customers on optional TOU and demand charge rates would show a slightly lower level of cost recovery when the majority of these

[108] *Id*.
[109] Miessner Direct 8:5-6.
[110] D.55931.

customers opted into these rates based on expected bill savings.[111] Rates are designed to reasonably reflect costs based on proxy measures designed for the average customer, meaning that many individual customers will pay more than the cost to serve them while others will pay less. Because APS has specifically marketed the TOU and demand rates to "natural savers"—those customers who would specifically save money under the tariff because their use is different than the residential class average—it is logical that customers who would have paid more than their "fair share" of costs on Schedule E-12 would seek the bill savings afforded to them on the other tariffs. The experience of those customers specifically identified as paying more than their share based on larger class averages cannot be extrapolated to mean that the rest of the residential customers would see similar, or any, savings.

Q. Do these findings imply that customers should be restricted from choosing other rate options that may save them money?

A. No. As stated above, matching rates with costs is but one goal to be considered in designing rates. The cost recovery from all residential customers across APS's tariff options is fairly similar (a spread of 83% to 92% in Vote Solar's analysis).[112] This is an acceptable level of variation when considered in conjunction with the important role that optional TOU and demand charge rates play in support of the other goals of rate design including enabling new technologies. Indeed this concept is part of APS's first goal described in its Long-Range Rate Plan which is: "[m]odernizing rates to enable new technologies and reflect the continued value of the electricity delivery system."[113]

APS's Plan states that "[c]ustomers today have meaningful opportunities to invest in DG, energy storage, electric vehicles, smart thermostats and appliances, home energy controls, advanced HVAC systems and other new technologies."[114] APS

[111] AURA 1.6c.
[112] *See* Figure 2.
[113] LRS-05DR at 2.
[114] *Id.* at 10.

additionally cites research that indicates that customer adoption of these technologies will continue to increase.[115] It is clear that the price signals in existing optional TOU and optional demand rates that also contain TOU energy rates are already enabling new technologies. Indeed, over half of APS's current residential customers have elected to take service on TOU or demand-plus-TOU rates, which provide some price signal and incentive for customers to shift load from the peak period.[116] While APS contends that under current rates, adoption of rooftop solar results in cost shifting, that claim has been proven false.[117] As a result, APS's proposal to implement mandatory demand charges for the majority of its residential and all of its smallest commercial customers will not alleviate unsustainable cost shifting because it is not occurring. And, even if it were, there is no evidence that demand rates for residential and small business customers reduce the cost shift. As noted above, the existing optional demand rates do a poorer job on this measure than the E-12 tiered energy rate. In reality, APS's proposal will simply restrict customer options, which may incent certain new technologies at the expense of others that are currently more cost-effective for customers under the current rate options.

5.2 Demand charges for residential and small business customers will not create actionable price signals

Q. Has APS provided any testimony regarding the ability of residential and small business customers to understand and respond to demand charges?

A. Yes. APS states that it has "extensive experience with residential three-part demand rates."[118] Mr. Snook states that "[r]esidential three-part rates will provide better price information to customers to help them manage their demand in

[115] *Id.*
[116] CAM_WP01DR – Proof of Revenue.xlsx.
[117] *See* Table 5.
[118] Miessner Direct 8:24.

addition to their energy consumption."[119] Mr. Miessner presents the results of a study purporting to show that "[c]ustomers on these rates have demonstrated they can respond to demand charges and manage their monthly demand on their bill. When customers switch to the rate, they typically reduce both their demand and energy consumption."[120]

Q. Has APS provided the details of this study?

A. Yes. APS has provided the data underlying its analysis of roughly 1,000 customers in the Phoenix metro region that switched from a two-part TOU rate to a three-part TOU demand rate between 2012 and 2014.[121] Of APS's study group, roughly 90% lowered their monthly bills.[122] An examination of the detailed results reveals that although most of the roughly 1,000 customers lowered their monthly bills, 40% of those customers actually increased their peak demand usage after transferring to the demand charge rate.[123] In fact, some customers were able to increase their peak demand usage as much as 10% and still save money on their monthly bills.[124] While APS uses the results of this study to make the claim that customers can respond to demand charges,[125] it is important to place the results of this study into context.

Q. In what context should these results be viewed?

A. APS's current group of residential customers on three-part rates have all elected to take service on those rates, rather than be required to take service on demand charge rates, as is APS's proposal in this case. This is a crucial distinction since I would expect customer demand management among opt-in customers to be stronger than among customers enrolled in mandatory demand rates. Indeed, in

[119] Snook Direct 32:19-20.
[120] Miessner Direct 8:26-9:2.
[121] Staff 5.37.
[122] Miessner Direct 20:13-14.
[123] Staff 5.37.
[124] *Id.*
[125] Miessner Direct 19:13-20:10.

one of the academic studies on voluntary demand charges cited by APS witness Dr. Faruqui, the author cautions against extrapolating results from an opt-in program to a mandatory program.[126]

In addition, it is evident that the subset of APS customers who have elected to take service on the optional demand charge rates are not representative of the residential class as a whole. The roughly 11% of residential customers who chose to take service on demand charge rates have average annual usage that is more than twice that of customers who did not choose demand rates.[127]

The disparity in annual usage between those opting for demand rates and other customers is also not surprising as survey evidence reveals that the majority of customers on the demand charge rate option chose the option based on a recommendation from APS.[128] APS customer service representatives only recommend that a customer take service on the demand charge rate based on expected savings, not based on a customer's ability to respond to the price signal in the demand charge.[129] When APS does not have prior usage information, its customer service representatives will suggest the demand charge rate option only for customers with homes that are larger than 2,000 square feet who also have a pool or spa.[130] This indicates that the customers taking service on the optional residential demand charge rates do so because they were specifically identified by APS as having different lifestyles and consumption patterns than the majority of APS residential customers. Indeed, APS instructed its customer service representatives to recommend the demand charge option with the following script: "It is clear you would be a natural saver on this rate without any changes to your

[126] Thomas N. Taylor, *Time-of-Day Pricing with a Demand Charge: Three-Year Results for a Summer Peak*, MSU Pub. Util. Papers, Award Papers in Public Util. Econ. and Regulation, 236 (Taylor Paper), http://ipu.msu.edu/library/pdfs/publications/Award%20Papers%20in%20Public%20Utility%20Economics%20and%20Regulation%20(1982).pdf.
[127] Schedule H-2.
[128] Staff 5.2 "Demand Rate Quantitative Research" March 4, 2016, slide 10.
[129] AURA 1.6c.
[130] *Id.* at 1.6d APSRC01145, p. 2 of 2.

lifestyle."[131] This means the optional demand rate experience is not representative of those who would be placed on a demand charge rate for the first time under APS's proposal. It also means the experience with the existing optional demand rates is that of customers who save based on preexisting usage characteristics, not that customers can respond to demand charges to save through changes to behavior and usage.

Q. Do you have any information about the level of engagement of the current demand rate customers?

A. In Mr. Miessner's testimony, he describes three types of customers taking service on the optional demand charge tariffs: (1) technology adopters, (2) customers with behavior modification, and (3) customers who do not actively manage their bill.[132] When asked in discovery to estimate the proportion of current demand charge customers that fall into each category APS stated that "based on customer bill savings and demand and energy reductions [in analysis referenced above] we believe that there are a significant number of customers in the first two groups."[133] However, APS's own survey data contradicts this statement.

Q. Please describe APS's survey data.

A. In response to discovery, APS provided a report addressing a survey of current demand rate customers.[134] The survey examined a variety of measures of customer plan awareness, satisfaction, and behavioral response.[135] While most customers reported being satisfied with the plan[136] and found it easy to manage overall energy costs,[137] this is likely due to the fact that APS specifically marketed this rate to a select group of customers identified as "natural savers."

[131] AURA 1.6d APSRC01146, p. 4 of 6.
[132] Miessner Direct 19:14-24.
[133] VS 1.34.
[134] Staff 5.2 "Demand Rate Quantitative Research" March 4, 2016.
[135] *Id.*, slide 2.
[136] *Id.*, slide 8.
[137] *Id.*, slide 7.

Even within this select group, 29% reported that it was difficult to manage overall household energy cost.[138]

The report's conclusions state:

- There is generally a low level of awareness among customers of a demand rate on their rate plan or the demand feature.
- Their ability to manage their energy cost is primarily from shifting energy usage to off-peak hours, leveraging the TOU dimension of the plan.
- They are less confident about their ability to manage demand—with nearly half (49%) saying that they do not know how to control demand or that it is difficult.[139]

Q. What do you conclude based on this survey information?

If 49% of customers specifically targeted for the demand rate do not know how to control demand or find it difficult to do so and 28% of the targeted customers are unaware that they are even enrolled on a rate plan with a demand charge,[140] it is unlikely that the majority of customers on demand rates are actually (1) technology adopters, or (2) customers with behavior modifications, as APS claims. Rather it is clear from the survey data that the third category of customers, those who do not actively manage their bills, make up a significant proportion of the current demand rate customers. This is consistent with the load analysis APS completed of customers who switched from the volumetric TOU rate to the demand charge rate described above. As many as 40% of those customers actually increased their peak demand, displaying the opposite behavior of what the demand charge tariff is intended to encourage.[141] Based on this information, it is clear that current APS demand charge customers experience significant bill savings without behavior modification and that a large proportion of these customers lack a basic understanding of the demand charges for which they are being billed.

[138] *Id.*, slide 4.
[139] *Id.*, slide 11.
[140] *Id.*, slide 6.
[141] Staff 5.37.

Q. How does this information relate to APS's claim that it has significant experience with residential three-part demand rates?

A. APS points to the fact that it has offered residential demand rates for more than thirty-five years.[142] Indeed, APS's residential demand charge tariff was originally approved in October 1980 as a mandatory tariff for new residential customers with refrigerated air-conditioning.[143] However, the Commission removed the mandatory requirement less than three years later.[144] The Commission reversed the mandatory demand charge, stating the change was "in response to complaints that the mandatory nature of the EC-1 rate produced unfair results for low volume users."[145] In addition, the Commission stated that removal of the mandatory demand charge would "alleviate the necessity for investment by low consumption customers in load control devices to mitigate what would otherwise be significant rate impacts under the EC-1 rate."[146]

The evidence from the early 80s, when APS was authorized to implement a mandatory demand charge for new residential customers with refrigerated air-conditioning, indicates that considerable customer backlash occurred due to significant rate impacts for low-usage customers.[147] When combined with the available evidence on customer response to optional demand charges in APS's territory, showing that a considerable number of customers who opted in did not reduce their peak demand, and survey data indicating low levels of customer understanding and engagement among opt-in customers, it is clear that customer response to a mandatory demand charge would likely be even more limited. The evidence indicates that APS's residential and small commercial customers will have little ability to respond to mandatory demand charges.

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[142] Miessner Direct 18:17.
[143] Decision No. 51472 (Oct. 21, 1980) (Ex. BK-SR-2).
[144] Decision No. 53615 (June 27, 1983) (Ex. BK-SR-3).
[145] *Id.* 7:18–19.
[146] *Id.* 7:20–22.
[147] *Id.* 7:18–19.

Q. Has APS provided evidence from academia and/or other utilities to indicate whether customers will be able to respond to the price signal in mandatory demand charges?

A. APS witness Dr. Faruqui provides information based on an academic review and the experience of other utilities in the attempt to make the case that "two-part rates [are] ineffective at providing the proper pricing signals" and "must give way to three-part rates."[148] In particular, Dr. Faruqui makes reference to more than forty pilot studies involving over 200 rate offerings that have found that customers respond to new price signals by changing their energy consumption patterns.[149] But in discovery, APS reveals that not a single one of these studies included a demand charge.[150]

Dr. Faruqui also cites to four studies that purport to show that customers respond to demand charges specifically, but review of those studies reveals that they all addressed voluntary demand charges.[151] Indeed, one study highlighted this fact, stating: "[i]t is emphasized that the findings of this experiment apply only to this volunteer population. It would not be appropriate to draw inferences from these results for a mandatory program."[152] Yet, directly contrary to this admonition, Dr. Faruqui is using the experiment to infer results for APS's proposed mandatory program.

Dr. Faruqui additionally provides a survey of other utilities in this country that have residential rates that include demand charges citing to "at least 20 utilities in 14 states that offer a three-part rate to residential customers."[153] This represents

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[148] Faruqui 25:16-20.
[149] *Id.* 18:14-17.
[150] VS 1.28.
[151] Studies provided in AURA 1.12.
[152] Thomas N. Taylor, *Time-of-Day Pricing with a Demand Charge: Three-Year Results for a Summer Peak*, MSU Pub. Util. Papers, Award Papers in Public Util. Econ. and Regulation, 236 (Taylor Paper), http://ipu.msu.edu/library/pdfs/publications/Award%20Papers%20in%20Public%20Utility%20Economics%20and%20Regulation%20(1982).pdf.
[153] Faruqui 16:3-4.

less than 1% of the electric utilities in the United States.[154] Even among this small group of utilities, the vast majority of the rates offered are optional. In a table in his testimony he claims that there are four utilities that impose mandatory residential demand charges: Butler Rural Electric Cooperative, Mid-Carolina Electric Cooperative, the Salt River Project ("SRP"), and Swanton Village Electric Department.[155] However, a review of these tariffs reveals that only two of these four rates are, in fact, mandatory. SRP's demand charge tariff is mandatory only for customers with DG and Swanton Village's demand charge is mandatory only for the largest residential customers.[156] This leaves Dr. Faruqui with only two examples of utilities in the United States with mandatory demand charges for residential customers, both of which are cooperatives, as opposed to state-regulated utilities.

Q. What do you conclude based on this evidence?

A. While there has been much rhetoric in the APS application about the need to "modernize" the rate structure, movement towards mandatory demand charges for residential customers in no way reflects modern trends in ratemaking. Importantly, no regulatory commission in the nation has imposed mandatory demand charges for residential customers. While APS has experience offering optional demand charge rates to residential customers for decades, an examination of the evidence reveals that these customers have atypically large levels of consumption and have been guided to the rate by APS based on expected savings rather than behavior modification. Indeed, a recent survey of APS's demand charge customers revealed that 49% of them do not know how to manage demand or find it difficult to manage demand while 28% were unaware they were even on a rate plan that included a demand charge.[157]

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[154] Staff 12.17b.
[155] Faruqui, Attach. AJF-2DR.
[156] *Id.*
[157] Staff 5.2 "Demand Rate Quantitative Research" March 4, 2016, slide 6

Dr. Faruqui states:

> Considering that APS has been offering its three-part rate on a voluntary basis among several other rate options, and considering that enrollment in the three-part rate has grown significantly over the past several years, this is a very strong indication that APS's customers are interested in and prepared for rates with demand charges.[158]

I strongly disagree. Rather, APS's decades-long offering of optional demand charge rates has resulted in the small subset of specifically targeted customers who fare better under demand rates choosing that option, even while many are apparently not even aware that they have. Just because something has worked for a select 10% of the population does not indicate that the other 90% would be well suited to a mandatory program.

5.3 Bill impacts associated with demand charges are highly variable and may lead to extreme customer dissatisfaction

Q. Has APS provided information about expected bill impacts from its demand charge proposal?

A. APS provided several measures of bill impacts expected from the revenue requirement increase and rate design proposals for the average customer. For example, APS indicated that a typical residential customer with usage of 1,083 kWh per month will see an $11.09 increase in their average monthly bill: roughly 7.96%.[159] In addition, APS Schedule H-4 provides numerous tables that delineate expected bill impacts by schedule and usage level with averaged peak billing demand. However, these representations all fail to account for the fact that residential demand charges will have disparate impacts on customers, not only based on energy usage level, but also based on peak billing demand. Imposing a mandatory demand charge will create winners and losers. As a result, it is not

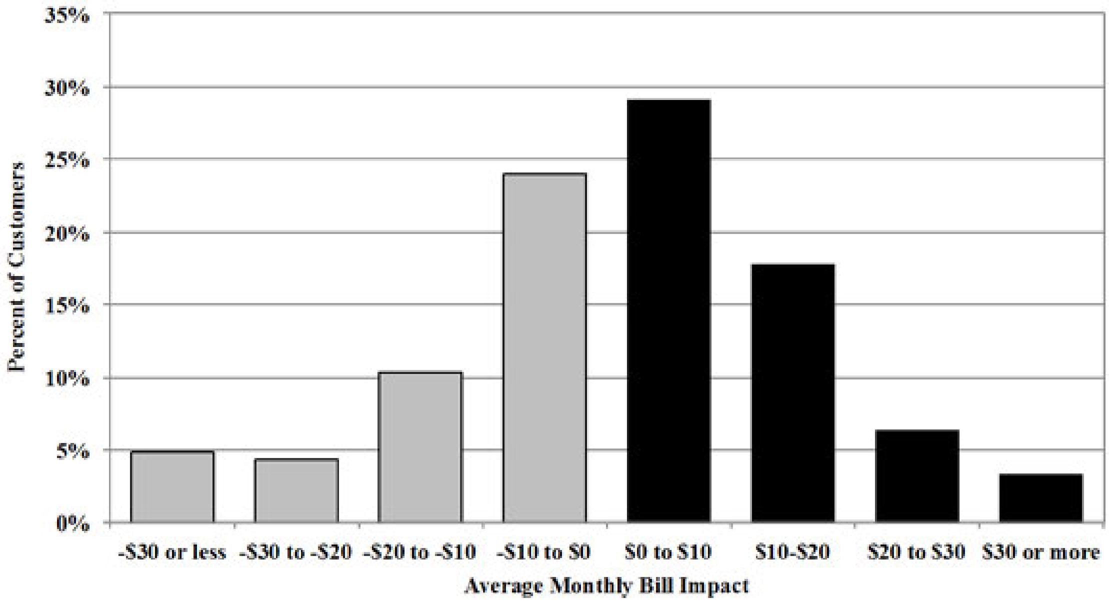
[158] Faruqui 21:7-11.
[159] Miessner Direct 47:4-5.

particularly meaningful to look at average impacts, but rather at the distribution of bill impacts.

Q. Have you developed an assessment of the distribution of bill impacts under APS's proposal?

A. Yes. Using billing data provided by APS in discovery, I examined expected bill impacts from APS's rate design proposals. In order to isolate the impact of the rate design changes from the revenue requirement increase, I compared monthly bills under current base rates scaled for APS's requested residential increase, with monthly bills under the proposed base rates for the group of customers that APS proposes to move from two-part rates to three-part rates. The results show that impacts will vary greatly among customers, with roughly 57% of customers expected to see bill increases and 43% of customers expected to see bill decreases. This is summarized in Figure 4 below.

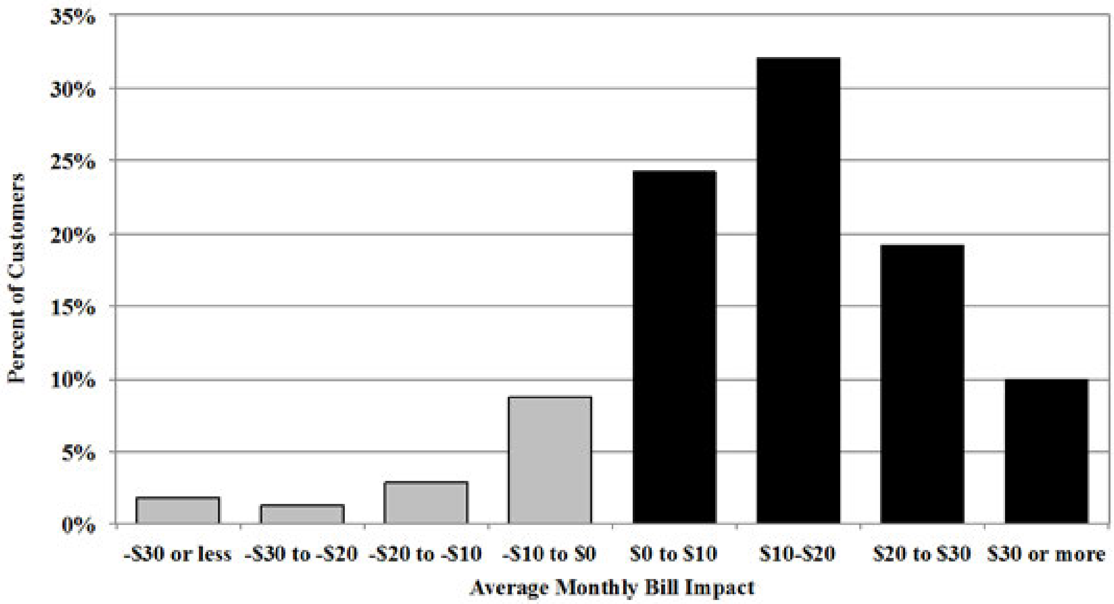
Figure 4: Distribution of Bill Impacts under APS Rate Design Proposal[160]



While roughly half of APS's customers will experience an average monthly bill impact from rate design of less than $10 in either direction, significant numbers of customers will face large bill increases under the APS proposal. Indeed 10% of customers, roughly 58,000 individual households will be subjected to monthly bill increases of more than $20 per month. These increases are on top of the increase from APS's proposed 7.96% increase in revenue requirements. When combined, approximately 30% of the customers who would be transitioned to three-part rates, roughly 174,000 individual households, will bear bill increases exceeding $20 per month. The distribution of combined impacts from APS's revenue requirement increase and rate design proposal is shown in Figure 5.

[160] Figure 4 reflects APS residential customers with and without DG who would be transitioned from a two-part rate to a three-part rate under the APS proposal.

Figure 5: Distribution of Bill Impacts under APS Rate Design and Revenue Requirement Proposals[161]



Q. **Have you examined the distribution of bill impacts among customers with DG?**

A. Yes. While impacts are relatively mixed for the broader residential class, solar customers who are moved from two-part rates to the proposed R-3 rate with a demand charge will see large systematic increases. This is shown in Figure 6 below.

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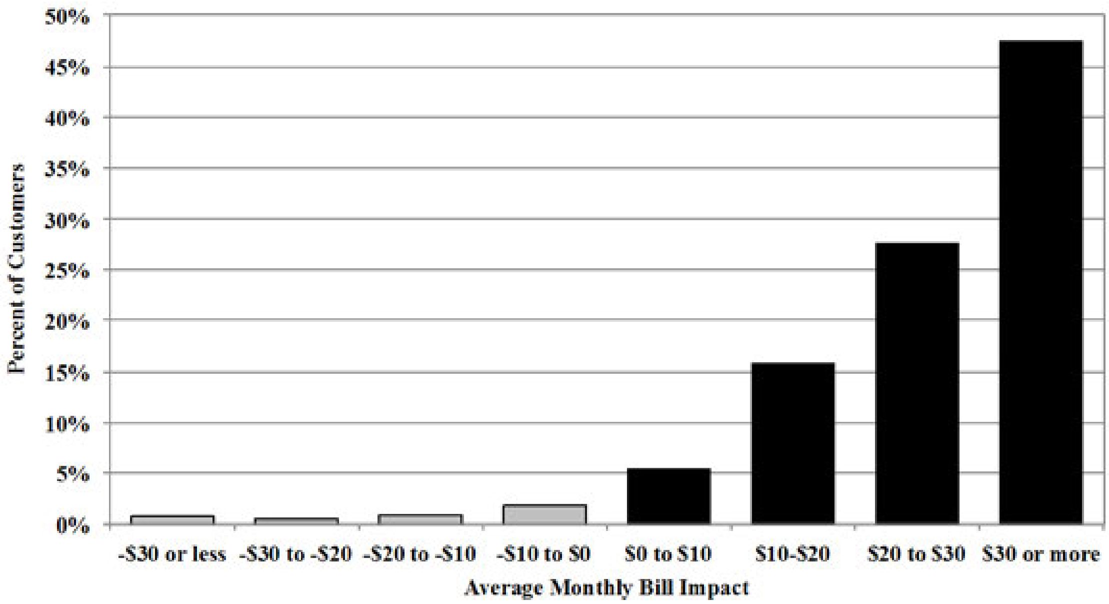
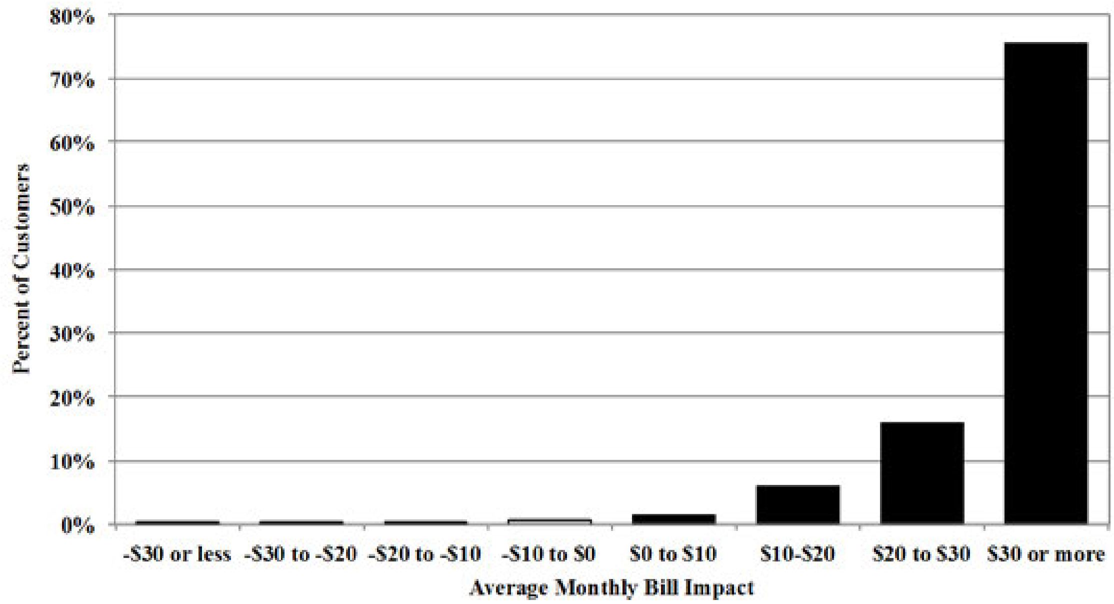
[161] Figure 5 reflects APS residential customers with and without DG who would be transitioned from a two-part rate to a three-part rate under the APS proposal.

Figure 6: Distribution of Solar Customer Bill Impacts under APS Rate Design Proposal



As shown in Figure 6, 75% of solar customers will face a bill increase of more than $20 per month. In fact, 10% of customers will face monthly bill increases above $50 due to the rate design change alone. Like the broader residential class, these changes will occur on top of those that would occur from the proposed revenue requirement increase. Combined bill impacts are shown in Figure 7 below.

Figure 7: Distribution of Solar Customer Bill Impacts under APS Rate Design and Revenue Requirement Proposals



Q. Will solar customers be better able to manage their bills under demand charges when compared to non-solar customers?

A. No. Solar customers are similarly situated to other residential and small commercial customers when it comes to their ability to understand and respond to demand charges. DG installations are effective at reducing a customer's energy consumption, and class-wide contribution to peak loading on the system, but even though solar generates significant levels of energy coincident with system peak, thereby reducing system load and demand costs, it does little to impact individual customers' peak billing demand. As shown in Table 4, rooftop solar reduced the load from DG customers between 35-41% at the time of system peak in the test year. In contrast, APS estimates that solar customers' solar generation will only reduce billed demand by 10%.[162]

[162] Staff 5.28.

Q. Are the range of bill impacts justified due to the link between demand charges and cost causation?

A. No. First, APS has not proven that demand charges improve the link between the rates paid by individual customers and the cost to serve them. In fact, as shown above, APS's COSS demonstrates that demand charge customers pay a smaller portion of the cost to serve them than tiered rate customers do. Second, the demand charges imposed in any 12 of 1,300 hours each year do not match the hours APS identified as cost causing. Third, in ratemaking, the goal of customer understanding and acceptance is equally important to the goal of cost-causation. Evidence from APS's current group of opt-in demand charge customers shows low levels of customer understanding and engagement and considerable difficulty responding to the price signal in demand charges. Moreover, there is a considerable lack of available evidence in academia and elsewhere that would lead one to conclude that mandatory demand charges are appropriate for residential customers.

Q. Why have so few utilities adopted demand charges for residential customers?

A. When asked what has prevented demand charge rates from being more broadly deployed to residential customers, Dr. Faruqui points to lack of sufficient metering technology.[163] While he is correct that prior to installation of Adanced Metering Infrastructure ("AMI"), it was not cost-effective for utilities to charge demand rates to residential customers, it is not metering technology alone that discouraged most utilities and all regulators from imposing mandatory demand charges for residential customers. There has also been significant public opposition.

While not included in Dr. Faruqui's list, Glasgow Electric Plant Board ("GEPB"), a Kentucky cooperative, implemented mandatory peak demand charges in January 2016 that were removed in September 2016 after significant customer

[163] Faruqui 16:11-14.

backlash.[164] Public outcry was so intense that the State Attorney General wrote a letter to the cooperative:

> As you are likely aware, my office is in receipt of numerous citizen complaints regarding the Glasgow Electric Plant Board's (GEPB) new rate schedule with coincident demand charges and increased customer charges. In response to these complaints, I recently directed my office to initiate an investigation into this matter.
>
> The current municipal rate schedule places an unequal burden on certain segments of Glasgow's customers including the residential and small commercial rate classes. The fixed charges for customers have doubled and, in some instances, tripled. The coincident peak demand charges are so outrageous customers report going to extreme measures to avoid these excess charges, including traveling between work and home five or six times a day to adjust their thermostat or appliances, and elderly customers turning off their air conditioning and staying in their homes, even after temperatures reach 92 degrees; yet, their bills continue to rise.[165]

Like GEPB, Illinois utilities ComEd and Exelon dropped their push for mandatory residential demand charges after public outcry and a memo from the Governor's Office labeling the proposal "insane."[166] The experience of these utilities exposes the significant customer backlash that can occur when rates send price signals that are difficult for customers to respond to.

Just last year, Unisource Electric ("UNSE") pushed for mandatory residential demand charges. UNSE was unable to provide evidence that customers would be

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164 Jackson French, *Glasgow Electric Plant Board Decides New Optional Rate* Bowling Green Daily News, Sept. 28, 2016. http://www.bgdailynews.com/news/glasgow-electric-plant-board-decides-new-optional-rate/article_05fbad4d-38d6-5c5b-8725-0f5fada9afe6.html.

165 Letter from Andy Beshear, Atty. Gen., Kentucky, to Glasgow Electric Plant Board (Aug. 25, 2016) http://blog.cleanenergy.org/files/2016/10/Beshear-GlasgowEPB2016.pdf.

166 Kim Geiger, *Comed, Exelon Drop Some Provisions in Controversial Bill*, Chicago Tribune, Nov. 22, 2016. http://www.chicagotribune.com/news/local/politics/ct-state-power-legislation-update-met-20161122-story.html.

able to respond to the price signals in demand charges. Indeed, an APS attorney went so far as to suggest that UNSE customers "go to a mall or a movie or something like that for awhile"[167] in order to avoid demand charges. As the responding witness correctly noted, for such an idea to work, folks would need to go to the mall every day in the month for five hours and that such a requirement would be very difficult, especially for lower-income customers.[168]

In Decision No. 75697 the Commission concluded "[t]he public distrust or antipathy to the proposal has convinced the Company and the Commission that any transition to three-part rates will require a massive public education effort before we can say with any degree of certainty that mandatory residential demand rates in UNSE's service territory are in the public interest."[169]

Decision No. 75697 aptly quoted Professor Bonbright's following statement:

> The administration of any standard or system of rate making has consequences, some of which are costly or otherwise harmful; and these consequences may warrant the rejection of one system in favor of some other system admittedly less efficient in the performance of its recognized economic functions. Thus an elaborate structure of rates designed to make scientific allowance for the relative cost of different kinds of service may possibly be rejected in favor of a simpler structure more readily understood by consumers and less expensive to administer. And thus a system of rate regulation that would come closest to assuring a company of its continued ability to earn a capital-attracting rate of return may be rejected in favor of an alternative system that runs less danger of removing incentives to managerial efficiency. The art of rate making is an art of wise compromise.[170]

I recommend that the Commission again consider this statement as APS's proposals are evaluated. While a small minority of APS's customers chose to take service on optional demand charge rates, it is clear that these customers did so

167 Docket No. E-04204A, Evidentiary hearing Tr. at 2494:18-21.
168 *Id.* 2494:22-2495:2
169 D.75697 65:15-18.
170 *Id.* 63:24-64:4.

based on APS's suggestion and expected bill savings without lifestyle changes, rather than engagement with or preparedness for responding to the price signal in demand charges. Imposing unfamiliar demand charges on the majority of APS's residential and all of APS's smallest business customers would create disparate, and in many cases extreme, bill impacts, especially but not exclusively on customers investing in rooftop solar. Given the lack of evidence that the demand charge rates better reflect cost, and the evidence that solar customers are currently recovering more than their fair share of costs under current rate design, there is no compelling reason to implement mandatory demand charges for residential and small business customers.

6 Restricting Solar Customer Rate Options Is Discriminatory

Q. Please describe APS's proposal for rate design for customers with DG.

A. APS proposes restricting the rate options of customers who choose to install DG after the grandfathered period. Under APS's proposal, new DG customers would be forced to take service on Schedule R-3, the demand charge rate with the highest relative demand charges and lowest relative volumetric rate.

6.1 The Commission has determined that the ratemaking implications of separate class treatment should be decided in this case

Q. Did the Commission provide any guidance on this issue in the recent Value of DG decision?

A. In Decision No. 75859 the Commission stated:

> We agree with APS that the appropriate test for the formation of a subclass of customers for purposes of rate design is whether a sub-group of customers is sufficiently different from the sub-group's current classification in

> regard to service, load, or cost characteristics to place that sub-group into a separate class. The record in this proceeding demonstrates that rooftop solar customers are partial requirements customers who export power to the grid, and we therefore find that rooftop solar customers are a separate class of customers. The ratemaking implications of this separate class treatment are to be determined in each utility's rate case supported by a fully vetted cost of service analysis.[171]

While the Commission found that the sub-group of residential customers that installed rooftop solar should be considered a separate class of customers, it reserved ruling on the implications of that separation until this case.

Q. How does this finding relate to APS's proposal to restrict DG customer rate options?

A. APS consistently argues that it may be appropriate to separate customers from within a rate class "if the service, load, or cost characteristics of the customer subgroup in question are sufficiently different from their current customer classification."[172] The Commission adopted this test in Decision 75859 and found separation was appropriate based on the finding that rooftop solar customers export power to the grid, thereby requiring a different service from the utility.[173] The Commission also adopted a methodology for valuing and compensating rooftop solar exports that will address this difference in service.

Q. Given the changes adopted in the Value of DG docket, is differential treatment of solar customers for rate design purposes necessary?

A. No. Differential rate design may be necessary for a subgroup of customers if the group is of sufficient size and a COSS demonstrates a significant mismatch between the subgroup of customers and the broader class. A corrected analysis in this case reveals that significant cost shifting is not occurring within the residential class and that solar customers recover more than their fair share of

[171] D.75859, 146:108.
[172] Snook Direct 24:3-5.
[173] D.75859, 146:4-6.

costs. While the Commission found that customers may be separated if service, load, or cost characteristics sufficiently differ from the sub-group's current classification, for purposes of ratemaking it is the cost implications of each of these criteria that are paramount. Each of these criteria is evaluated in the COSS, which plainly demonstrates that no cost shift exists.

First, differences in service were addressed through the Value of DG docket's determination that exports should be compensated based on a credit rate rather than netted against onsite consumption at the retail rate. While APS makes the claim that additional services such as inrush current must be provided to solar customers, these services are in fact provided to all residential customers, and the accepted allocation factors in the COSS fully account for the costs associated with these services.

Differences in load is the second criterion for subclass separation. Differences in load can be fully captured in the COSS by examining the costs to serve solar customers based on delivered load. This fully captures the unique load shape of customers with rooftop solar and allows for an examination of the cost implications of that load shape.

Finally, and most importantly, the final criterion is cost. As established above, the results show that solar customers are paying more than their fair share of costs under the current rate design, implying that the cost to serve these customers is not "sufficiently different" so as to warrant discriminatory rate treatment. Indeed, to discriminate against solar customers without any evidence of a significant cost differential would open the door to separation of other subgroups of the diverse residential class.

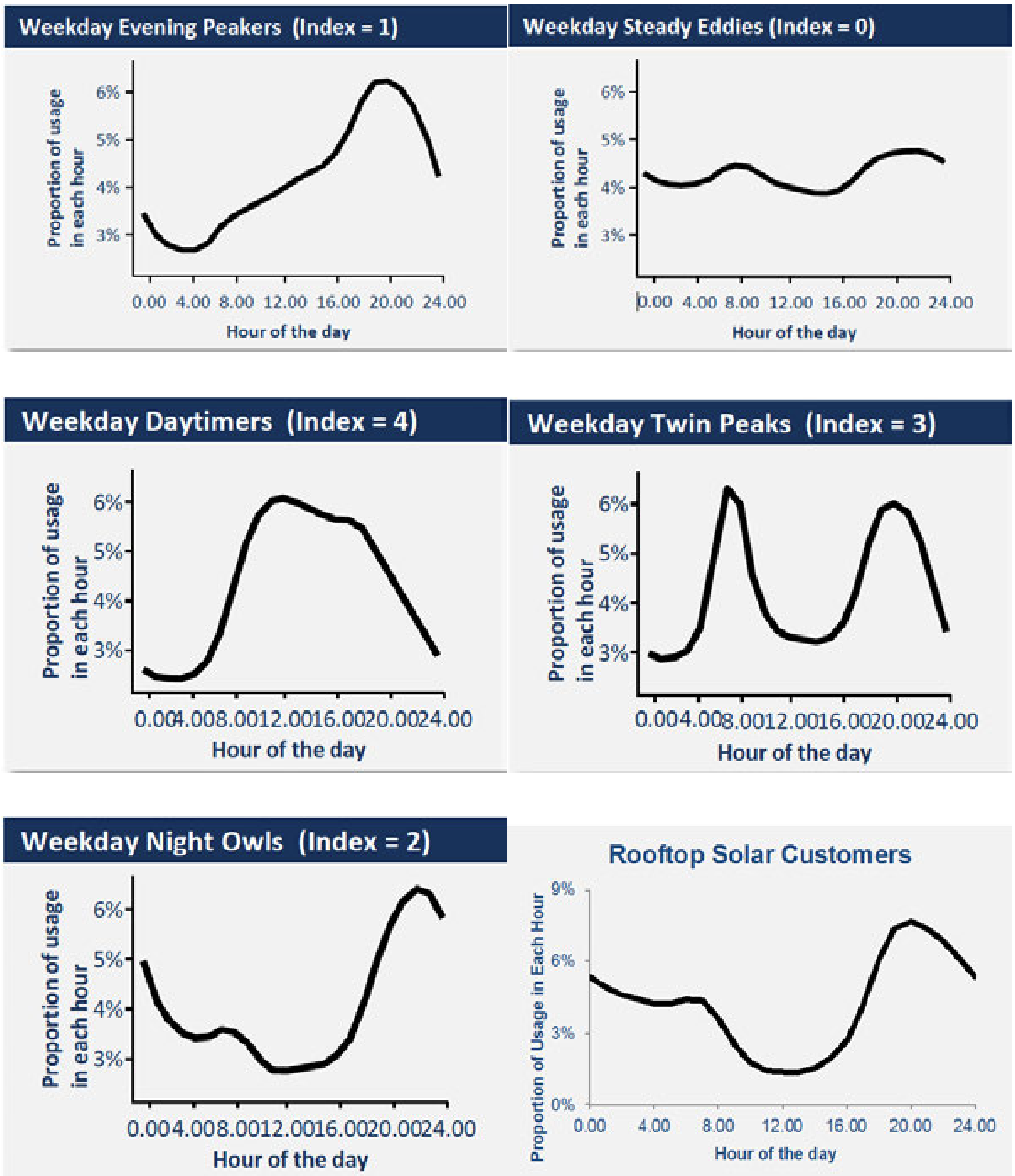
6.2 <u>Solar customers do not have sufficiently different load or cost characteristics to warrant differential rate treatment</u>

Q. Is there any evidence to illustrate diversity of customer load in the residential class?

A. Yes. APS has developed a study of different load profile types that exist within the residential class and presented the results of that study in its Third Technical Conference in this case.[174] In that study APS identified five different types of residential customers with very different usage patterns. Illustrative load shapes from these customers are shown in Figure 8 below. Also shown in Figure 8 is the load shape from APS's rooftop solar customers developed based on information provided in discovery.[175]

[174] APS Rate Case Third Technical Conference presentation, September 29, 2016, slide 14.
[175] SEIA 1.17

Figure 8: APS Residential Customer Load Types[176]



In response to discovery, APS indicated that the residential class breaks down into the five customer types as shown in Table 9 below.

[176] APS Rate Case Third Technical Conference presentation, September 29, 2016, slide 14, SEIA 1.17.

Table 9: Residential Customer Class by Customer Type[177]

Customer Type	Percentage of Customers
Weekday Evening Peakers	42%
Weekday Steady Eddies	19%
Weekday Daytimers	16%
Weekday Twin Peaks	10%
Weekday Night Owls	10%
Rooftop Solar Customers	3%

Results from the APS study demonstrate that considerable diversity exists within the residential class. There are several distinct groups of customers larger than the group of rooftop solar customers with highly varying load shapes that could have potential implications for cost recovery, yet it is only solar customers who APS has chosen to isolate for analysis in its COSS and it is only solar customers APS singles out for proposed differential rate treatment. Based on APS's test, as approved by the Commission, each of these customer types, like the "Weekday Twin Peaks" could be interpreted as having a sufficiently different load shape to warrant separation as a separate rate class.

6.3 There is no evidence of significant cost shifting within the residential class and solar customers pay more than their fair share of costs relative to other residential subgroups

Q. Do you have any evidence of relative cost to serve residential customer subgroups?

A. I have not studied the cost recovery differentials of the five customer types identified by APS in Figure 8. However, I have developed an analysis of the relative cost to serve other customer subgroups based on a study that was completed by APS in the Value of DG docket.[178] In this study APS provided data

[177] VS 2.5, CAM_WP01DR, assumes that APS study of load types did not include rooftop solar customers.
[178] Docket No. 14-0023

on the load shapes of (1) winter visitors, (2) apartment dwellers, and (3) dual fuel customers that can be compared with customers with rooftop solar and the broader residential class.[179] I requested that APS provide an updated version of the study based on current test year data, but APS declined.[180] As a result I developed an update to APS's analysis that includes test year cost information.

Q. Please explain your methodology for updating APS's study of relative cost recovery from residential customer subgroups.

A. Building on the analysis conducted to correct APS's flawed COSS assumptions described in Section 4.2, I developed an assessment of the relative cost to serve winter visitors, apartment dwellers, and dual fuel customers for comparison with the cost to serve all residential customers with and without solar who take service on APS's various rate options. I was unable to update the load shapes for (1) winter visitors, (2) apartment dwellers, and (3) dual fuel customers. As a result these customers' load shapes are based on 2014 data as opposed to 2015 data. For purposes of this analysis I do not expect that such an update would have a material impact on the results.

Q. Please summarize your results.

A. My results indicate that cost recovery differences exist within the residential class. Figure 9 below provides a visual representation of the relative cost recovery from various subgroups of residential customers. Results for each subgroup are benchmarked to average cost recovery from residential customers without rooftop solar. As shown in Figure 9, the lowest recovering subgroup is dual fuel customers at 82% of the non-solar residential average and the highest recovering subgroup is winter visitors at 132% of the non-solar residential average.

[179] Snook Direct in 14-0023, 25:13-28:2
[180] VS 3.8e

Figure 9: Residential Subgroup Cost Recovery Comparison

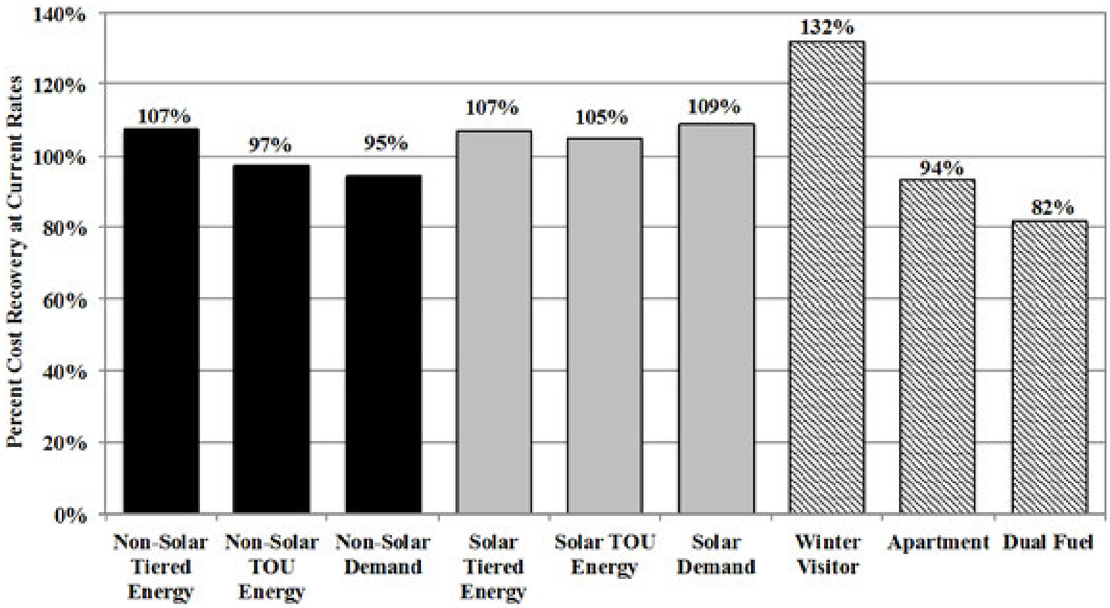


Figure 9 presents the same results from the COSS analysis discussed above: customers with rooftop solar recover more than their fair share of costs under current rates. It also demonstrates that comparing cost recovery from winter visitors, apartment dwellers, and dual fuel customers reveals greater variation than between customers with and without solar. Interestingly, Figure 9 shows considerable differences in cost recovery from winter visitors who appear to subsidize other customers under current rate design. If demand charge rates are implemented as proposed, with large winter demand charges out of sync with demand-based costs that are driven almost exclusively by summer demands, the subsidy from winter visitors will be exacerbated.

Q. Based on these results would it be appropriate to implement differential rate designs for these subgroups of customers?

A. No. It is a policy question for this Commission whether the winter customer subsidization or dual fuel customer cost shift illustrated in Figure 9 is significant enough to warrant additional consideration. However, I caution that restricting rate options for small customer groups due to differing consumption patterns and small differences in cost recovery would be a slippery slope toward segregation of other portions of the residential and small commercial classes (*e.g.*, by cooling equipment, or urban vs. rural customers). In my opinion the results provided in Figure 9 demonstrate two important things: (1) while cost shifts exist within the residential class, solar customers pay a proportion of costs similar to non-solar customers; and (2) solar customers are currently paying more than their fair share of costs under current rate design. Solar customers not only pay rates that cover their costs, but also do not represent a sizeable subgroup when compared to the various customer types shown in Figure 8 and Table 9. As a result, separate rate treatment for solar customers would be discriminatory and should not be approved in this case.

Moreover, piecemeal subdivision of the residential and small commercial classes would add significant complexity to the ratemaking process. The residential class inevitably contains customers with widely varying consumption patterns, yet including these customers in the same rate design is in the public interest. In addition to the examples above, cooling technology can drive significant differences in customer load factors, and urban customers with higher population density can have a lower per-customer cost to serve than rural customers who may require lengthy line extensions and serve fewer customers from each piece of shared equipment. I am again reminded of the quote from Professor Bonbright: "an elaborate structure of rates designed to make scientific allowance for the relative cost of different kinds of service may possibly be rejected in favor of a simpler structure more readily understood by consumers and less expensive to administer."[181] I encourage the Commission to consider these words and avoid discriminatory subdivision of the residential class for solar customers and other groups of customers.

[181] Bonbright Principles of Public Utility Rates 1961, 37-38.

7 Vote Solar Proposed Rate Design

Q. Have you developed a proposed alternative to the residential and extra-small commercial proposals developed by APS?

A. Yes. I describe my proposal for residential and extra-small commercial rate design below, including (1) grandfathering customers who file for interconnection of DG prior to the effective date of the rates in this proceeding, (2) rejecting APS's proposed restrictions on the modified net metering rider, (3) maintaining current customer rate options, (4) maintaining basic service charges at current levels, (5) modifying the peak period to be defined as 2 p.m. to 7 p.m., (6) allowing DG customers the same rate options as other customers including discontinuation of rider LFCR-DG for new DG customers, and (7) adding a meter fee to new DG customers to recover the incremental capital and labor costs associated with bidirectional meters; and (8) rejecting proposed modifications to the LFCR. Each of these recommendations is described in detail below.

7.1 Existing DG Customers Should Be Grandfathered onto Retail Rate Net Metering and Current Rate Design Options

Q. What are your recommendations regarding grandfathering of existing DG customers?

A. It is essential that the Commission safeguard existing DG customers from drastic and unforeseen rate design changes. APS's existing DG customers made investments in rooftop solar systems to serve their family or small business's needs based on price signals APS and the Commission were sending at the time. In fact, many of those customers were specifically encouraged to invest in DG through up-front incentives. Those customers responded correctly to the price signals and incentives; and, by investing in rooftop solar, those customers fixed a portion of their electricity bills to offset fluctuating electricity rates. Many of these customers invested in rooftop solar as part of a long-term financial plan, perhaps tied to retirement, college, or some other anticipated financial need. By investing in their own energy source, these customers can reduce monthly expenses when their system is paid off, improving savings potential much like paying off a mortgage. Drastic, unforeseen changes to the rate design for these customers have the potential to severely undercut their planned savings.

Q. What has APS proposed regarding grandfathering?

A. APS proposes to grandfather DG customers who have filed for interconnection by July 1, 2017.[182] These systems would be grandfathered for a period of twenty years from the initial interconnection date and in the case of a change of ownership would stay with the system, rather than the customer.[183] In addition, APS proposes to implement "legacy" tariff options for residential and extra-small commercial customers with DG that would allow them to take service on the existing rate schedules modified to include the proposed revenue requirement changes.[184]

Q. Do you agree with APS's proposal for grandfathering?

A. Largely, yes. I recommend only one small clarification: that the deadline for grandfathering be linked to the effective date of the rates adopted in this proceeding, rather than July 1, 2017. This is important in case an unanticipated delay in the procedural schedule prevents implementation of the rates approved in this case by July 1, 2017.

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[182] Miessner Direct 46:6-10.
[183] *Id.* 46:11-12, 15.
[184] *Id.* 25:21-23, Proposed Schedule E-32 XS Legacy.

7.2 Additional restrictions should not be placed on the modified net metering rider

Q. Does APS propose modifying net metering riders with its application?

A. Yes. APS proposes to place new solar customers who file for interconnection after the grandfathering deadline on a revised net metering rate rider EPR-6S.[185] APS proposes to replace net metering with a credit rate for exported generation. This structure is consistent with the Value of DG decision. Because the credit rate will be the subject of future testimony I will not provide comment on the merits of APS's proposed credit rate at this time. However, in addition to setting the credit rate, APS proposes to impose restrictions on enrollment on Rider EPR-6S that should be evaluated by the Commission.

Q. What restrictions does APS propose for enrollment on Rider EPR-6S?

A. APS proposes to restrict enrollment on EPR-6S to residential and commercial customers with installed generation of 100 kW or less.[186] APS proposes that customers who do not qualify for EPR-6S be placed on Rider E-56R which includes purchase for exports at near-term avoided cost, currently 2-3¢/kWh.[187]

Q. Does this restriction exist under the current net metering program?

A. No. The current net metering rate rider EPR-6 does not restrict systems to 100 kW or less, and indeed, many commercial customers have installed systems in excess of 100 kW under the current net metering program.[188] Like the proposed EPR-6S, current rider EPR-6 does restrict system sizing to 125% of a customer's total

[185] *Id.* 45:5-7.
[186] *Id.* 45:5-7.
[187] Current Riders E-56R and EPR-2.
[188] http://arizonagoessolar.org/SolarMap.aspx

connected load, a limitation that is codified in the Commission's net metering rules.[189]

Q. Was this restriction to systems under 100 kW addressed in the Commission's Value of DG docket?

A. No. Decision No. 75859 that outlined the Commission's intended replacement for net metering did not include any discussion nor determination regarding modification of the net metering facility definition as codified in Rule 14-02-2301(13)(d). It appears that APS's proposes arbitrary limits on the criteria for participate in the modified net metering program.

Q. Has APS provided information regarding the rationale for these proposed restrictions?

A. No. I asked APS for additional information on this topic in discovery which I will review and provide comment on in my surrebuttal testimony.

Q. Do you recommend that APS's proposed restrictions on modified net metering enrollment be approved?

A. No. The Commission's net metering rules carefully contemplated restrictions that should be placed on customer enrollment in the original net metering program and determined that net metering facilities should be limited to 125% of total connected load. Additional restrictions were not discussed in the Value of DG docket and are not warranted.

[189] R.12-02-2302(13)(d)

7.3 Existing residential and extra small commercial rate options should be maintained

Q. What do you recommend for residential and extra small commercial rate options?

A. I recommend that APS maintain the existing rate options for residential and extra small commercial customers. For residential customers this includes optional service on (1) the E-12 tiered rate, (2) the ET-2 two-part TOU rate, (3) the ECT-2 three-part TOU rate, (4) the ET-SP two-part advanced TOU rate, and (5) the ET-EV rate for electric vehicle customers. For extra-small commercial customers I recommend that the current options—(1) two-part non-TOU, and (2) two-part TOU—be maintained with an additional optional three-part TOU rate. APS has additionally proposed to eliminate the second tier of the E-32 XS tariff.[190] I support eliminating this tier.

Q. Why do you recommend maintaining current rate options?

A. While APS developed an application strongly urging wide-scale adoption of demand charges for residential and extra small commercial customers, I have not found evidence to support the need for this type of drastic and unprecedented rate design change. In particular:

- APS has not established that rates with demand charges improve the link between costs and rates. Indeed, APS's own COSS finds that customers enrolled on demand charge rates recover the lowest percentage of cost to serve when compared with other tariff options.
- Evidence from APS's current group of customers enrolled on the optional demand charge rate indicate low levels of understanding and customer engagement with large proportions of customers who find it difficult to manage demand, or lack knowledge that they are even enrolled on a demand

[190] Miessner Direct 50:8-14.

charge rate. I expect customer engagement and understanding to be even lower with a mandatory program.

- Mandatory demand charges will create highly variable and in some cases extreme bill impacts. Given the lack of compelling evidence that rates with a demand charge will improve the link between rates and costs and the lack of evidence that customers will be able to meaningfully respond to the price signal presented by a demand charge, this change is likely to produce extreme customer dissatisfaction without tangible economic benefit.

Moreover, evidence from the COSS and the residential subgroup comparison analysis reveals that Schedule E-12 results in the highest relative cost recovery from the residential class when compared to other residential tariff options. These findings are consistent with the Commission's determination in 1988 when Schedule E-12 was being evaluated in relation to other tariffs: "Schedule E-12 […] generally reflects the cause and effect relationship between the use of electricity for central refrigerated air-conditioning, the dramatic increase in the total system demand during the summer months, and the demand-related costs (as well as energy costs) incurred by APS to meet its summer peak."[191]

When considering optimal residential rate design it is important to consider the diverse set of customers for whom rates will be applicable. To this end, it is critical that rates be understandable and that options be provided for customers who may wish to take service on more complex rates. APS should consider pursuing additional customer education efforts to further increase the already substantial proportion of customers who take service on the optional TOU and demand charge rates, but there is no compelling evidence that the current suite of rate design options must be significantly modified.

[191] D.55931.

7.4 Basic service charges for residential and extra small commercial customers should not be increased

Q. What does APS propose for residential and extra small commercial basic service charges?

A. APS proposes large increases to the basic service charges for residential and extra small commercial customers. Current and proposed basic service charges are summarized in Table 10 below.

Table 10: APS Current and Proposed Basic Service Charges ($/month)

Rate Schedule	Current	Proposed
E-12	$8.67	n/a
ET-2, ECT-2	$16.91	n/a
R-XS	n/a	$18.00
R-1, R-3	n/a	$24.00
R-2	n/a	$14.50
E-32 XS Self Contained Meter	$20.44	$35.28
E-32 XS Instrument Rated Meter	$40.27	$61.44
E-32 XS Primary Meter	$103.87	$150.47

As shown in Table 10, APS's proposal would nearly triple the basic customer charge for some residential customers and would increase extra small commercial customer charges by 40-70%,

Q. How do the residential customer charges compare to charges approved for other utilities?

A. Puget Sound Energy recently conducted a study of electric utility basic service charges, surveying charges from 107 utilities across the country as part of its 2017 General Rate Case.[192] The average basic customer charge from these utilities was $9.17/month.[193] Based on this group of utilities, APS's proposed low-end

[192] PSE fixed charge survey UE-170033 - UG- 170034 17. 2017 GRC Piliaris direct attach 16 PSE 01-13-2017.PDF attached to testimony of Jon Pillaris.
[193] *Id*.

residential customer charge of $14.50/month falls in the 90th percentile of customer charges and APS's proposed high-end customer charge is second only to one other utility, falling in the 99th percentile of customer charges.

Q. What is APS's basis for the proposed increase to basic service charges?

A. APS proposes including a number of additional costs in the basic customer charge that are in excess of costs related to customer meters, billing, and customer service. This includes a portion of the costs related to grid operations, communications, and cyber security equipment as well as distribution transformers that APS admits varies with potential electrical load at the customer's premises.[194]

Q. In your opinion is it appropriate to include these costs in the customer charge?

A. No. The basic customer charge should be limited to recovery of costs directly related to the number of customers that do not vary based on the demand of the customer. This includes meters and meter-reading expenses, customer service, and billing.

Q. Do APS's proposed increases to the basic customer charge present policy implications?

A. Yes. An increase in basic customer charge will result in a commensurate decrease in other components on the customer's bill. Raising the customer charge and lowering volumetric or demand charges will decrease customer control over their bills and will dampen the price signal embedded in the rate. APS's first goal in the long-range rate plan is to "modernize rates to enable new technologies."[195] However, a high fixed charge is not a "modern" rate design, but rather a regressive, blunt instrument that would discourage the adoption of new technologies.

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[194] Miessner Direct 31:24-32:11.
[195] LRS-05DR, p. 2.

Q. What do you recommend for basic customer charges in this case?

A. I recommend that the current E-12 basic customer charge of $8.67/month be maintained. I also recommend that the customer charges on the optional ET-2 and ECT-2 tariffs be lowered to be consistent with the E-12 customer charge to make these tariffs more attractive to lower-consumption customers, thereby incenting greater adoption of these optional rates. In addition, I recommend that the current customer charges on Schedule E 32 XS and E-32 TOU XS be maintained.

7.5 Residential and commercial peak period should be redefined

Q. What does APS propose regarding the peak period for residential and commercial customers?

A. APS proposes modifying the existing peak periods for the residential and E-32 commercial classes. The residential peak is currently defined as 12 p.m. to 7 p.m., and the E-32 peak is currently defined as 11 a.m. to 9 p.m. For both classes of customers APS proposes redefining the peak as 3 p.m. to 8 p.m. APS indicates that the proposed period was developed based on an assessment of hourly percent of peak on APS's system during the highest summer weekdays.[196]

Q. Have you reviewed APS's assessment?

A. I have. APS provided a spreadsheet containing various measures of system demand percentage related to the top weekday consumption on its system in 2015.[197] Based on this information it is clear that the earlier hours of the existing peak periods, namely 11 a.m. to 2 p.m., show lower system usage than the later hours of the existing peak. This suggests that it is appropriate to reconsider APS's current peak period definition.

[196] VS 1.44
[197] CA_WP04DR.xlsx

Q. What do you recommend for defining the residential and E-32 class peak period?

A. Based on the evidence reviewed, it is appropriate to shorten the peak period to allow for a more precise price signal and to focus customer incentives on the hours in which peak shifting would be most beneficial to the system. I do not, however, agree with APS's proposal for a 3 p.m. to 8 p.m. peak period. Namely, the percent of peak usage exhibited in the 7 p.m. to 8 p.m. hour is lower by all measures than the percent of peak usage exhibited in the 2 p.m. to 3 p.m. hour. This is summarized on Table 11 below.

Table 11: APS Hourly Percent of System Peak Load (HR = Hour ending)

	HR15	HR16	HR17	HR18	HR19	HR20
Top 10 Average	95%	98%	100%	100%	96%	93%
Top 20 Average	95%	98%	100%	100%	96%	93%
Top 30 Average	95%	98%	100%	100%	96%	93%
Top 40 Average	95%	99%	100%	99%	96%	93%
Top 50 Average	95%	98%	100%	99%	96%	93%
Top 60 Average	95%	98%	100%	99%	96%	93%
Top 70 Average	95%	98%	100%	99%	96%	93%
Top 80 Average	95%	98%	100%	99%	96%	94%
Average - All Days (Jun-Sep; Weekdays)	95%	98%	100%	99%	96%	94%

As shown in Table 11, the percent of peak load in the HR15 column, which is 2 p.m. to 3 p.m., is higher by every measure than the percent of peak load in the HR20 column, which represents 7 p.m. to 8 p.m. Therefore, while I can accept APS's proposal to shorten the peak period for residential and E-32 customers, I recommend that the peak period be defined as 2 p.m. to 7 p.m. on weekdays excluding holidays.

7.6 DG customers should be afforded the same rate options as other residential customers

Q. Do you propose any differential rate design for DG customers?

A. I do not. DG customers should be afforded the same rate options as all other residential customers. My review of the COSS indicated that DG customers pay more than their fair share of costs under current rate design and that while minor cost shifts do exist within the residential class, DG customers are currently providing a net benefit to other residential customers. In addition, because DG customers pay more than their fair share of costs under current rates, APS should freeze Rider LFCR-DG for new DG customers who will not take service under retail rate net metering.

7.7 Residential DG customers should pay a meter fee to capture the incremental capital and labor costs associated with the bi-directional meter

Q. Please describe the meter fee that you propose for residential customers with DG.

A. As indicated in Section 4.1.3, above, I recommend that the incremental capital and labor costs associated with solar customers' bi-directional meters be captured with a meter fee consistent with the ALJ's Recommended Order and Opinion in the TEP case. Data received from APS in discovery indicate that the total installed cost associated with the standard residential meter is $134.54 and the total installed cost associated with the bi-directional meter is $431.44.[198] Comparing the two figures results in an incremental capital cost of $296.91.

The meter fee approved in the ALJ's Recommended Opinion in Order in the TEP case was based on a levelized carrying charge developed by TEP from a study of

[198] VS 7.5.

marginal customer costs for that utility.[199] I am not aware of a similar study conducted by APS. In order to develop an initial proposed monthly meter fee I employed the TEP carrying charge in this case but would encourage further refinement of the methodology in collaboration with other parties to this proceeding, and specifically APS.

Using the methodology approved by the ALJ's Recommended Opinion and Order in the TEP case, I propose that new DG customers who sign up after the grandfathering deadline be charged a monthly fee of $4.26 to capture the incremental capital costs associated with their bi-directional metering equipment. In lieu of this monthly fee I additionally propose that customers be afforded the option to instead pay a one-time upfront charge of $296.91 upon interconnection.

7.8 <u>The LFCR should not be modified</u>

Q. What is the LFCR?

A. The LFCR is a "narrowly tailored" partial decoupling mechanism that is designed to support energy efficiency and DG "at any level or pace set by this Commission."[200] The LFCR was agreed upon through settlement negotiations during APS's last general rate case and reflects a compromise between numerous parties. The LFCR is designed to recover "a portion of distribution and transmission costs related to sales level that are reduced by EE and DG and exclusion of the portion of distribution and transmission costs recovered through the Basic Service Charge ("BSC") and 50 percent of the costs that are recovered through non-generation/non-TCA demand charges."[201]

Q. Has APS proposed modifications to the LFCR in its Application?

A. Yes. APS proposes a number of modifications to the LFCR. These include but are not limited to: (1) increasing the year-over-year cap to 2%, (2) allowing for

[199] Jones Direct 29:21-24 in 15-0239, Ex. CAJ-1.
[200] Decision No. 73183 Ex. A, p. 6.
[201] D.73183, Ex. A, page 10.

recovery of costs currently excluded from the LFCR, and (3) changing the LFCR from an equal percentage surcharge to a demand charge for most customers.[202]

Q. Has the Commission provided guidance on this topic in the rate cases of other Arizona utilities?

A. Yes. Both UNSE and TEP proposed similar modifications to their LFCR mechanisms in recent and currently open rate cases.[203] Like APS, UNSE proposed to increase the year-over-year cap to 2% and to allow for the recovery of additional costs currently excluded from the LFCR.[204] In Decision No. 75697 the Commission rejected UNSE's proposals, finding: "[t]he LFCR mechanism is not intended to operate as a full de-coupler mechanism, but rather to collect the lost fixed cost revenues associated with Commission-mandated programs such as Energy Efficiency and DG."[205] TEP's open rate case includes a similar proposal. The ALJ's Recommended Opinion and Order similarly rejects the utility proposal with the exception of allowance for costs related to reliability must-run generation.[206]

Q. Are the Commission's findings for UNSE and TEP relevant in this case?

A. Yes. In both the UNSE and TEP rate cases, the Commission recognized that the current LFCR appropriately balances the utility's desire to recover fixed costs with Commission policy that promotes certain levels of energy efficiency and DG adoption. APS's proposals to increase the year-over-year cap and to include categories of costs that are expressly excluded from the current LFCR should be rejected as counter to the "narrowly tailored" LFCR derived from multi-party settlement and previously approved by this Commission.

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[202] Snook Direct 36:11-22.
[203] UNSE Docket No. 14-0142; TEP Docket No. 15-0039.
[204] D.75697, 123:1-5.
[205] D.75697 126:9-11.
[206] TEP ROO in Docket No. 15-0039, 165:2-24.

Q. Do you have any additional comments on APS's proposal to modify the LFCR from an equal percentage surcharge into a demand charge?

A. Yes. APS's proposal to modify the LFCR from an equal percentage surcharge to a demand charge should be rejected. As outlined in detail above, mandatory demand charges for residential and extra small commercial customers are not in the public interest. APS has not provided any rationale for modification of the LFCR structure. The LFCR is a partial decoupling mechanism meant to recover lost fixed costs related to the energy efficiency and DG programs. There is no relationship between these costs and individual customer demand. Moreover, it appears as though APS intends to charge customers for the LFCR based on the maximum demand in each month regardless of the time period in which the demand is reached.[207] This may result in residential customers incurring an LFCR charge based on maximum demand reached outside the peak period that APS encouraged customers to shift load away from. Such a proposal will likely exacerbate customer dissatisfaction and increase customer confusion in the event that APS's proposal for near-mandatory demand charges is approved.

8 Conclusions and Recommendations

Q. Please summarize your conclusions on APS's proposals.

A. As I have shown in my testimony, APS has not provided sufficient basis to support its proposal for large-scale rate design modification including the implementation of mandatory demand charges on residential and all extra small commercial customers. While APS has attempted to make the case that such changes are warranted due to cost shifts resulting from rooftop solar and the relationship between demand charges and the cost APS incurs to serve its customers, both of these claims have been proven false. As I demonstrate in my testimony, APS employed a number of inappropriate assumptions in its COSS analysis that resulted in the assessment that solar results in a $1 billion cost shift.

[207] Proposed Adjustment Schedule LFCR.

When corrected, the evidence demonstrates that solar customers overpay relative to the broader residential class under current rate design and that, rather than a cost shift, current solar customers provide a net benefit of $60 million under conservative assumptions.

I have also demonstrated that mandatory demand charges are not good policy. There is no evidence that demand charges for residential customers improve the link between cost causation and individual customer bills, and indeed APS's own study reveals that current customers on demand charge rates pay the lowest proportion of the cost to serve them when compared with customers on the other tariff options. I find that the group of residential customers that have elected to take service on a demand charge rate are not representative of the broader residential class. Usage data reveal that large proportions of these customers actually increase peak demand after enrolling in the rate, and survey information reveals low levels of customer engagement with and even understanding of the demand charge aspect of their current rate plan. I find that APS's proposal to implement mandatory demand charges would create disparate and in many cases extreme bill impacts, especially but not exclusively on customers investing in rooftop solar. In light of these findings, I conclude that mandatory demand charges are not in the public interest and recommend that they should be rejected by this Commission.

Given that no solar cost shift exists, that current solar customers produce a $60 million net benefit to other customers, and that mandatory demand charges are not in the public interest, I find that APS's proposal that customers investing in DG after the grandfathering deadline be restricted to choosing rate schedule R-3 is not warranted. A study from APS of residential customer load shapes demonstrates that solar customers do not have sufficiently different load characteristics to warrant differential rate treatment and, in fact, larger groups of customers with highly varying load shapes exist within the residential class. In addition, an analysis of cost recovery from various solar customers relative to non-solar residential customers and other residential subgroups including seasonal customers, apartment dwellers, and customers with natural gas service in their homes demonstrates that that while minor cross-subsidization exists, there is no significant cost shifting within the residential class under current rate design. As a result I recommend that the Commission find that APS's proposal to restrict rate options available to solar customers is not based on the evidence and would be discriminatory.

Q. What are your rate design recommendations for the Commission?

A. I recommend the following:

- Existing DG customers should be grandfathered into retail rate net metering and current rate design options.
- Additional restrictions should not be placed on the modified net metering rider and APS's proposal to restrict enrollment on Rider EPR-6S to systems less than 100 kW should be rejected.
- Existing residential and extra small commercial rate options should be maintained.
- Basic service charges for residential and extra small commercial customers should not be increased.
- The peak period should be redefined as 2 p.m. to 7 p.m.
- DG customers should be afforded the same rate options as other residential customers.
- DG customers who sign up for interconnection after the grandfathering deadline should not be subject to Rate Rider LFCR-DG.
- DG customers who sign up for interconnection after the grandfathering deadline should be charged a monthly meter fee of $4.26. In lieu of the monthly fee customers should have the option to pay a one-time upfront charge of $296.91.
- The LFCR structure should not be modified at this time.

Q. Does this conclude your testimony?

A. Yes, it does.

CERTIFICATE OF SERVICE

ORIGINAL and 13 COPIES of the

Foregoing filed this 3rd day of February, 2017, with:

Docketing Supervisor
Docket Control
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

Copies of the forgoing mailed/delivered/emailed this 3rd day of February, 2017, to:

All Parties of record.

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Signature of Sender

Exhibit BK-1

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PROFESSIONAL EMPLOYMENT

Program Director – DG Regulatory Policy, Vote Solar
August 2015-present

- Analyze policy initiatives, development, and implementation related to distributed solar generation
- Review regulatory filings, perform technical analyses, and testify in commission proceedings relating to distributed solar generation

Senior Associate, MRW & Associates
April 2007-August 2015

- Develop and sponsor expert witness testimony for numerous clients to assist intervention in the utility regulatory process including investor-owned utility general rate cases, policy rulemakings, utility applications for power plant and transmission development, and other rate-related proceedings
- Represent clients at regulatory workshops, hearings and settlement discussions
- Perform in-depth quantitative analysis of utility models and testimony in support of general rate case and other regulatory proceedings
- Conduct extensive analysis of energy policy, regulation, economics, and emerging energy trends
- Build and maintain spreadsheet models to forecast utility rates and rate components tailored to client needs
- Create analytical models to assess generator production, profitability and electricity costs under a variety of regulatory and market scenarios and conduct pro forma analyses and technical assessments of infrastructure development in support of business decisions
- Provide analyses to investors and developers on the impact of laws, regulations, and procurement practices on potential sales of generation in various markets, assess current procurement progress, estimate pricing expectations for power sales, identify potential considerations that affect the marketability of project generation
- Provide policy recommendations to the State of California regarding greenhouse gas reduction, nuclear power generation and natural gas storage

EDUCATION

University of California, Berkeley
Bachelor's of Science with Honors, Environmental Economics and Policy

PREPARED TESTIMONY

- CPUC Application A.14-06-014
  Testimony of Briana Kobor on behalf of the Coalition for Affordable Streetlights Concerning SCE's Proposed Street Light Rates. March 13, 2015.
- CPUC Application A.14-11-003
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  Direct Testimony and Exhibits of Briana Kobor on Behalf of Vote Solar. December 9, 2015.
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  Direct Testimony and Exhibits of Briana Kobor on Behalf of Vote Solar. February 25, 2016.
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- Mehta, Heather, Kobor, Briana, & Weisenmiller, Robert. California Plans a Carbon Diet. Project Finance Newswire, Chadbourne & Parke. January 2009.