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BEFORE THE ARIZONA CORPORATION COMMISSION

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COMMISSIONER

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION

DOCKET NO. E-00000J-14-0023

THE ALLIANCE FOR SOLAR CHOICE'S (TASC) NOTICE OF FILING REBUTTAL TESTIMONY OF R. THOMAS BEACH AND WILLIAM A. MONSEN

The Alliance for Solar Choice ("TASC") hereby provides notice of filing the Rebuttal Testimony of R. Thomas Beach and William A. Monsen in the above referenced matter.

RESPECTFULLY SUBMITTED this 7th day of April, 2016.

Arizona Corporation Commission
DOCKETED
APR 07 2016
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/s/ Court S. Rich
Court S. Rich
Attorney for The Alliance for Solar Choice

Arizona Corporation Commission
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Original and 13 copies filed on this 7th day of April, 2016 with:

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BEFORE THE ARIZONA CORPORATION COMMISSION

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IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION

DOCKET NO. E-00000J-14-0023

REBUTTAL TESTIMONY OF R. THOMAS BEACH

Executive Summary

This rebuttal testimony responds to the opening testimony of the other parties to this proceeding on the benefits and cost of renewable distributed generation (DG) resources in Arizona.

My direct testimony for TASC proposed a benefit-cost methodology for valuing DG resources that builds upon the widely-used, industry-standard approach to assessing the cost-effectiveness of other types of both demand- and supply-side resources. When applied to DG resources, these analyses assess the benefits and costs of DG from multiple perspectives, including those of the principal stakeholders in DG development, including (1) participating customer-generators, (2) other non-participating ratepayers, and (3) the utility system and society as a whole. The goal of the regulator should be to balance the interests of all of these stakeholders, who collectively constitute the public interest in developing renewable DG technologies.

This rebuttal testimony responds to the testimony of the utilities who advocate the use of cost of service studies (COSS) or market prices to assess the cost-effectiveness of renewable DG. COSS are based on utility costs in only a single test year, and thus fail the capture the full benefits and costs of renewable DG over the long-term life of these resources. A COSS is likely to underestimate the long-run costs avoided by renewable DG, particularly avoided capacity costs for generation, transmission, and distribution. COSS are not used to judge the cost-effectiveness of other types of resources, such as utility-owned resources. Although market prices (where they exist) are useful for assessing portions of the benefits of DG, they do not cover all of the benefits; in particular, they do not cover the avoided costs for transmission and distribution capacity. Further, markets are only beginning to be used to value important externalities such as environmental costs.

This rebuttal testimony observes that the parties to this case agree on many of the benefits and costs of renewable DG. I discuss several benefits on which there is not agreement: fuel hedging and market price mitigation. A primary objection is that the amount of DG output is not sufficient to produce such benefits. This argument is belied by the current penetration of DG resources in Arizona today (3% and growing) as well as by the utilities' recognition that customer-sited resources – including energy efficiency and demand response as well as DG – are now a significant resource on which they are relying to meet future resource needs. Further, this growing industry promises to provide broad economic benefits for the state of Arizona, particularly if businesses in Arizona leverage the state's leadership position, abundant solar resources, and local expertise to serve markets for distributed renewable resources outside of Arizona.

Finally, this rebuttal responds to the testimony of the Residential Utility Consumer Office (RUCO). RUCO argues that, in assessing the benefits and costs of renewable DG, the perspective of non-participating ratepayers should be emphasized. My testimony argues that the Commission should prioritize the Societal Test, which is also the test used to evaluate the cost-effectiveness of other demand-side programs in Arizona. RUCO's preference for the Ratepayer Impact Measure (RIM) Test is not justified by the differences between DG and other types of demand-side resources. Upon closer inspection, these differences are not significant enough to warrant the use of a different test. Moreover, if the Commission shares RUCO's concern that only a subset of ratepayers have access to DG technologies, the Commission should take note that middle-income ratepayers now are the most common solar adopters. In addition, there are model programs in other states that are extending the availability of solar to renters, homeowners with shaded roofs, and low-income customers. Instead of favoring non-participating ratepayers, the Commission should look equally at the perspectives of both participating and non-participating ratepayers, and should seek to balance these viewpoints in order to best serve the public interest of all ratepayers.

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I. INTRODUCTION / QUALIFICATIONS

Q1: Please state for the record your name, position, and business address.

A1: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q2: Have you previously submitted direct testimony in this docket?

A2: Yes, I have. On February 27, 2016, I submitted direct testimony in this docket on behalf of The Alliance for Solar Choice ("TASC"). My experience and qualifications are described in my *curriculum vitae*, which is attached to my direct testimony as **Exhibit 1**.

II. PURPOSE

Q3: What is the purpose of this rebuttal testimony?

A3: My direct testimony presented TASC's proposal for how the Commission should establish the long-term value of distributed generation (DG) in Arizona, through an analysis of the benefits and costs of DG technologies. My testimony also addressed how the results of this cost-effectiveness methodology should inform the Commission's further consideration of the rates that apply to DG customers, or of future changes to the structure of net energy metering (NEM) in Arizona. This rebuttal testimony will not repeat that proposal in detail. Instead, this rebuttal focuses on responding to the proposals of other parties, including the Utilities Division Staff (Staff), the Residential Utility Consumer Office (RUCO), Arizona Public Service (APS), and Tucson Electric Power Company and UNS Electric, Inc. (TEP). I also provide responses to the questions that several commissioners have posed in this proceeding; these responses draw upon both my opening testimony and this rebuttal.

Q4: How is your rebuttal testimony organized?

A4: My opening testimony discussed four key attributes of a methodology to assess the benefits and costs of net metered DG resources.

1. **Analyze the benefits and costs in a long-term, lifecycle time frame.** The benefits and costs of DG should be calculated over a time frame that corresponds to the useful life of a DG system, which, for solar DG, is 20 to 30 years. This treats solar DG on the same basis as other utility resources, both demand- and supply-side.

2. **Focus on NEM exports.** The retail rate credit for power exported to the utility is the essential characteristic of net metering. There would be no need for net metering if no power was exported, and without exports a DG customer appears to the utility grid as simply a retail customer with lower-than-normal consumption.

3. **Consider a comprehensive list of benefits and costs.** DG resources are different than utility-scale, central station resources in their location, diversity, and technologies. As a result, DG resources will require the analysis of a broader set of benefits and costs than, for example, traditional QF facilities installed under PURPA.

4. **Analyze the benefits and costs from the multiple perspectives of the key stakeholders.** Examining all of these perspectives is critical if public policy is to support customer choice and equitable competition between DG providers and the monopoly utility.

This rebuttal is organized with sections on each of these attributes, and I review the extent to which the proposals of the other parties also share these attributes. I first discuss the broad issue of the role of benefit/cost studies in the Commission's regulation of DG resources. This issue is directly related to the first two attributes of DG – they are long-term resources that export power to the electric grid. I then discuss the differences between the parties on the specific benefits and costs of DG, and conclude with observations on why the Commission should take care to balance the perspectives of all stakeholders in Arizona's growing DG resources – participating ratepayers, non-participating ratepayers, the utility, and the state as a whole. This rebuttal concludes with the responses to the commissioners' questions.

III. THE REGULATORY CONTEXT FOR DISTRIBUTED GENERATION BENEFIT/COST STUDIES – DG IS A LONG-TERM RESOURCE, AND MUST BE EVALUATED AS SUCH.

Q5: Several witnesses, notably Mr. Brown for APS, argue that the Commission should not consider, or should place less weight on, long-term benefit / cost analyses in deciding the regulatory treatment of DG in Arizona. Please provide some context for why the Commission should consider such studies, and why they are essential.

A5: Renewable distributed generation – solar, wind, biomass, small hydro – are long-term generation resources that will have useful lives of 20-30 years producing clean, renewable electricity. If the utility were proposing to build and operate these distributed resources (or any other new resource, of any size), it would apply to this Commission to place them into its rate base, and would have to show, in a rate case, certification proceeding, and integrated resource plan, why the long-term benefits of these new resources exceeded their long-term costs, so that ratepayers in Arizona would benefit from their construction and operation over the resources' useful lives. The utility's showing of the benefits of these new resources undoubtedly would include many of the same long-term benefits of DG that the parties to this case have presented. These benefits would focus on the future costs that the utility would avoid through the construction of the new resources: avoided energy costs, avoided generation capacity, lower line losses, reduced T&D costs, lower emissions of pollutants, other environmental benefits, and reduced costs to comply with RPS requirements. Utilities even include difficult-to-quantify economic benefits in justifying new resources.[1] The cost of the new resources would be the present worth of the utility revenue requirement over their useful lives. This showing of the cost effectiveness of new resources is essentially a showing that the resources pass the Total Resource Cost (TRC) and Societal Tests discussed in my direct testimony. Such a showing of the long-term benefits and costs of new resources is standard practice for state regulators in the U.S., for both supply- and demand-side

[1] Vote Solar's Ms. Kobor notes the long-term rate stability benefits that TEP has cited to justify its acquisition of a combined-cycle plant. Vote Solar Kobor, at pp. 10-11.

resources, and is an essential process that enables a state commission to find that new resources are just and reasonable for recovery through the utility's rate base.

It is interesting that Mr. Brown's copious scorn for cost-effectiveness analyses of DG resources is not shared by the other witnesses for APS. Mr. Albert, who actually does resource management for APS, testifies that:

> … a Value of Solar (VOS) calculation can play a valuable role for policy makers. The VOS can inform resource planning decisions and can be used to evaluate and even establish how rooftop solar is incentivized. For example, the Commission can consider the VOS in determining the amount paid to customers who export energy to the grid from their rooftop solar systems. The Commission could also use the VOS to establish additional transparent incentives, such as the up-front cash incentive that the Commission authorized for a period of time.[2]

Mr. Sterling for APS provides testimony discussing a collaborative process that the Tennessee Valley Authority (TVA) undertook in 2014-2015 with a broad range of stakeholders to establish the value (the benefits net of the costs) of distributed resources in TVA's service territory. His testimony documents the substantial, but not complete, consensus that this process achieved.

Q6: What is different about renewable DG resources, compared to utility-owned generation?

A6: The difference is that, with renewable DG, it is customers, not the utility, who are making the long-term investment in these new resources. Renewable DG serves a portion of the loads of the customers who install it, displacing purchases from the utility. The remaining DG output is exported to the utility where it serves neighboring customers, also displacing generation from the utility system. Renewable DG represents customers exercising a competitive choice to purchase, in part, a product different from what the utility offers. Because today's utility business model ties earnings directly to the utility's rate base, the choice of DG will reduce the utility's future profits to the extent that, with

[2] APS Albert, at p. 2.

customer-sited DG on its system, the utility will add less rate base to serve a lower demand for its power.

Q7: How does this financial interest impact a utility's perspective on a long-term cost effectiveness analysis of new DG resources?

A7: A utility whose future financial returns are threatened by renewable DG faces a conflict of interest in presenting a balanced view of the long-term benefits and costs of DG resources.

Q8: Would a utility with such a conflict of interest be more likely to support setting rates for DG customers based on an embedded cost-of-service study (COSS)?

A8: Yes. A COSS is based on a single "test year" snapshot of the utility's costs, either a recent historical year (as in Arizona) or a near-future test year (as in other states such as California). As a result, unlike a benefit / cost analysis such as the TRC / Societal Tests, a COSS does not capture the long-run costs that DG can avoid over its full life. Moreover, most states, including Arizona, use a COSS approach based on the utility's embedded costs, not its marginal costs. Thus, a change in the utility's cost-of-service as a result of DG adoption has no direct link to how the company's costs may actually change when customers begin to produce their own power on their own premises. As discussed in the rebuttal testimony of Mr. Monsen, the COSS that APS has submitted overestimates the costs and underestimates the benefits of DG in a variety of ways. First, APS allocates costs to DG customers based on their total end use loads, rather than their lower metered usage from the grid. In effect, APS would charge DG customers for loads which the customers serve on-site using their own generation which never touches the grid. Second, Mr. Monsen shows that distribution substation and primary distribution costs should be allocated using a coincident peak allocator similar to that used for generation. Third, APS assumes that the avoided costs that result from DG output include only the avoided costs for generation energy and capacity. As summarized below, the parties to this proceeding have recognized many additional categories of benefits from DG that APS does not include in its COSS.

Q9: Are COSS used to establish the reasonableness of utility rate base additions or other types of demand-side programs, such as energy efficiency (EE)?

A9: No, they are not. A utility would object if the Commission judged the merits of a rate base addition solely on whether it raised rates for customer based on the COSS in the next rate proceeding. Utility-scale generation additions often raise rates in the short-run, for several reasons. First, the cost recovery for utility-owned resources through rate base is front-loaded into the early years. Second, large utility-scale capacity additions can result in a significant period of over-capacity. Notwithstanding their high initial net cost, such additions but may be justified based on long-term savings compared to the counterfactual alternatives. Similarly, energy efficiency programs often give consumers a rebate or incentive to adopt an energy-saving measure. The rebates increase rates in the short-run, but these costs are offset by the long-term savings. The same considerations apply to customer-sited DG resources, and the same long-term analyses should be used to judge the merits of DG resources.

Q10: Mr. Brown for APS opines that "[o]ptimally, prices should be established by market forces. This is not always possible. Where market imperfections exist, the discipline of a competitive market is missing, and it is appropriate to regulate based on costs in order to best replicate what would have happened if the market were shorn of its imperfections."[3] Are markets a viable option for assessing the benefits and costs of DG in Arizona?

A10: I agree with Mr. Brown that it is preferable to use markets and market prices to establish the benefits of DG. This is possible where energy markets exist, are well-functioning, and bear directly on certain of the benefits of DG. For example, past DG benefit/cost analyses that Crossborder has performed[4] have used the following market prices:

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[3] APS Brown, at p. 5.

[4] These studies include:

- *Evaluating the Benefits and Costs of Net Energy Metering in California*, prepared for the Vote Solar Initiative, January 2013 ("California Study"). See http://votesolar.org/wp-content/uploads/2013/01/Crossborder-Energy-CA-Net-Metering-Cost-Benefit-Jan-2013-final.pdf .

- Avoided energy costs: Locational marginal prices (LMPs) in California,[5] PJM[6], and ISO-NE[7], as well as current and forward natural gas market prices throughout the U.S.[8]

- Avoided capacity costs: capacity prices in PJM[9] and ISO-NE.[10]

- Locational benefits of DG: LMPs in California[11] and Vermont.[12]

- Avoided carbon costs: California cap & trade market prices for GHG allowances.[13]

- Avoided renewables costs: REC markets in the West.[14]

The challenge in Arizona is that, unlike other regions of the country, the utilities are vertically integrated, there is no retail competition, the only wholesale market is the regional energy market at Palo Verde (which lacks visible hourly prices), there are no transparent REC or carbon markets, and there are no locational prices on the transmission grid. Our system of federalism allows states to regulate electric utilities as they see fit, and I fully respect the choice that Arizona has made. Given the lack of relevant markets within the state, an analysis of the benefits of DG in Arizona has little market data on

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- *The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina*, October 2013 ("North Carolina Study"). See http://c.ymcdn.com/sites/www.energync.org/resource/resmgr/Resources_Page/NCSEA_benefitssolargen.pdf.
- Direct Testimony of R. Thomas Beach on behalf of MDV-SEIA, in Virginia SCC Case No. PUE-2011-00088, October 2011 ("Virginia Study").
- Pre-filed testimony of Patrick G. McGuire and R. Thomas Beach for Allco Renewable Energy Limited in Vermont Docket 8010, September 2014 ("Vermont Study").
- *Benefits and Costs of Solar DG for Arizona Public Service (2016 Update)*, February 2016, submitted as Exhibit 2 to my direct testimony in this case ("Crossborder APS Study").

[5] California Study.
[6] Virginia and North Carolina Studies.
[7] Vermont Study.
[8] All referenced studies.
[9] Virginia Study.
[10] Vermont Study.
[11] California Study.
[12] Vermont Study.
[13] See Crossborder APS Study, at p. 8. APS relies on California cap & trade market prices for the forecast of direct emission costs. See 2014 Integrated Resource Plan (IRP), at Figure 15.
[14] Testimony of R. Thomas Beach on behalf of the Sierra Club in Utah PSC Docket 15-035-053 (September 2015).

which to draw, and must use the available cost data, including forward-looking data such as the utility IRPs, to determine what the utilities' costs would have been absent DG.

Also, it should be noted that, even when competitive well-functioning markets do exist, they will not necessarily result in clearing prices that cover generators' full costs. For example, the California market, by design, has resource adequacy policies that require market participants to contract for sufficient excess capacity to ensure that there will not be any capacity shortages even at high levels of demand. As a result, the CAISO's market prices are not sufficient to support the entry of new generation. The CAISO's Annual Reports for many years have reported that its markets do not allow anywhere close to full recovery of the capital and operating costs of new gas-fired generation.[15] Thus, competitive markets are a means to an end (the efficient allocation of resources), but are not an end in themselves. To pay gas-fired generators average costs through bilateral contracts, or to allow utility-owned resources cost recovery through the rate base, and then to claim that the "value of solar" should be determined by energy market prices, ignores the fact that an energy market does not cover all of the costs of traditional generation resources or the full costs of the resources that DG might displace. Thus, prices established by market forces can be an important source of information, but they are unlikely to tell the entire story.

Q11: Would you agree that a significant "market imperfection" is that markets often fail to internalize the environmental costs of energy production and use?

A11: Yes. Compared to when Public Utilities Regulatory Policy Act was enacted in 1978, today we have a far deeper understanding and ability to quantify the costs to ratepayers of pollution and of the value of conserving scarce energy and water resources. Moreover, the potential impacts of global climate change have increased the importance and urgency of addressing these issues so that our children will inherit a habitable planet. The fact that there are only a few markets in the U.S. that internalize environmental costs does not

[15] For example, see CAISO, *2014 Annual Report on Market Issues and Performance* (June 2015), at Chapter 1, pp. 51-55, available at http://www.caiso.com/Documents/2014AnnualReport_MarketIssues_Performance.pdf.

mean that these impacts are zero for utility ratepayers or for the broader society. Quantifiable environmental benefits, such as reductions in carbon emissions, may not be a direct cost to ratepayers today, but they do influence resource planning and long-term costs, and they may become a direct cost in the future. Quantifiable environmental benefits should be considered in the Commission's deliberations on balancing the benefits and costs of DG.

Q12: Are there other reasons why analyses of the benefits and costs of DG are complex?

A12: Yes. Unlike a central station resource, DG is installed on the distribution system, and will impact not only the utility's generation costs, but also its transmission and distribution (T&D) costs. As a result, DG benefits can include avoiding line losses and T&D capacity costs. Solar and wind DG provide a product that is delivered directly to loads, which is a fundamentally different product than what is supplied by utility-scale solar plants or wind farms whose power must be delivered by the utility. For this reason, as discussed in my direct testimony, one cannot necessarily compare directly the busbar costs of utility-scale and DG solar and conclude that a less-expensive utility-scale solar plant offers greater benefits to ratepayers. For example, Mr. Brown makes this error in his busbar comparisons of the levelized cost of energy from various generation sources.[16]

Finally, because renewable DG is a long-term resource, evaluating its cost-effectiveness necessarily must involve long-term forecasts of many variables which are inherently uncertain. In addition, the analysis necessarily involves comparing different resource scenarios, many of which will be counterfactual. For example, demand-side resources including DG and energy efficiency will reduce the future loads that the utility must serve. However, we will never experience what the world would have been without these resources, which makes it challenging to judge the set of alternative resources that DG and energy efficiency have avoided and will avoid. However, as these resources reach significant scale, the evidence of what they are avoiding may become more apparent. For example, Pacific Gas & Electric (PG&E) recently announced to the

[16] APS Brown, at pp. 16-17.

California Independent System Operator that it is cancelling 13 sub-transmission projects in its service territory, which would have cost $192 million, as a result of "a combination of energy efficiency and rooftop solar," according to PG&E.[17]

IV. CONSIDER A COMPREHENSIVE LIST OF BENEFITS AND COSTS

Q13: Do the parties generally support a comprehensive set of benefits and costs of solar DG?

A13: Yes. There is significant commonality in the benefits and costs that parties recommend that the Commission should consider, as reflected in the following lists provided by the parties:

- TASC: Beach direct, at Table 2
- RUCO: Huber direct, at pages 17-23
- Staff: Solganick direct, Exhibits HS-2 and HS-3
- APS: Sterling direct, discussing the TVA value streams for DG
- Vote Solar: Kobor direct, at pages 27-36

The list of benefits and costs of DG that these parties recommend for Commission consideration are shown below in **Table 1**. The benefits or costs on which there is apparent disagreement on whether they should be included are shown in the table in **red** and noted with an "*".

[17] See "Cal-ISO Board Approves Annual Transmission Plan," *California Energy Markets* (No. 1379, April 1, 2016) at p. 10.

Table 1: *Summary of Benefits and Costs of DG*

Category	Notes
Benefits	
Energy	Includes fuel and variable O&M savings
*** Fuel hedging**	
*** Market price mitigation**	
*** Grid Services**	
Generation capacity	
Line losses	Both transmission and distribution
Transmission capacity	
Distribution capacity	
Avoided renewables costs	Avoided costs to comply with RPS
Avoided environmental costs	Includes avoided carbon emission costs
Costs	
Lost revenues	For the RIM Test
Capital and O&M cost of DG resources	For the TRC / Societal Tests
Integration	
Interconnection	If not paid by the DG customer
Program administration	

Q14: Please discuss the disagreement over whether fuel hedging benefits should be included as a direct benefit of solar DG.

A14: TASC, RUCO, Staff, and Vote Solar include fuel hedging benefits. The TVA study cited by APS witness Sterling considered a fuel hedging benefit, but did not include it because TVA study participants calculated that the benefit was negligible.[18] APS witness Brown dismisses fuel hedging benefits unless solar DG power can be produced "both in sufficient quantities and in a timely manner."[19]

The fuel hedging benefit results from the fact that renewable generation will displace and reduce the consumption of natural gas, which is the marginal fuel for producing electricity. As a result, utility ratepayers will be less subject to the volatility in natural gas prices, and in this way renewable DG can provide a fuel hedging benefit. With respect to Mr. Brown's assertion that renewable DG must be produced in sufficient volume to result in fuel hedging benefits, the strong growth of renewable DG throughout

[18] TVA Study, at p. 10. Available at www.tva.gov/dgiv.
[19] APS Brown, at p. 36.

the U.S., including in states such as Hawaii (approaching 20% penetration by number of customers[20]), California (4% penetration[21]), and Arizona (3% penetration[22]), shows that this condition has been satisfied. APS's 2014 IRP demonstrates that the utility is now planning on customer-sited resources – including energy efficiency, demand response (DR), and DG – to provide a significant share of the utility's future resource needs.[23]

Q15: Do the parties disagree on how to calculate fuel hedging benefits?

A15: Possibly. I agree with RUCO and Vote Solar that, at a minimum, the fuel hedging benefit of renewable DG should be recognized by using a long-term gas price forecast that is based on forward natural gas prices. Such a forecast represents a gas price that theoretically could be fixed for a future period, thus eliminating price volatility. However, this step may not recognize all of the costs that utility hedging programs incur to minimize volatility, including transaction costs. For example, APS's hedging program appears to have resulted in significant additional costs over an extended period.[24] To the extent that the historical record establishes these added costs for hedging, they should be included as costs that can be avoided if DG reduces the need to hedge volatile fossil fuel prices.

Q16: The testimonies of TASC, the Staff, and Vote Solar recognize that renewable DG may benefit ratepayers generally by reducing energy market prices. Do the other parties address this benefit?

A16: Lower energy market prices are a direct benefit to utility ratepayers. RUCO's proposal and the TVA methodology sponsored by APS witness Sterling do not address this

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[20] As of October 2015, 17% of all customers on Oahu and 18% of all customers on Maui had installed solar systems. See Hawaii PUC Order No. 33258, at p. 161 (Table 3, showing DG penetration). Available at http://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A15J13B15422F90464.

[21] California now has 3.9 GW of behind-the-meter DG and almost 500,000 solar customers connected to the grid (representing about 4% of the state's electric customers). *See California Solar Statistics*, https://www.californiasolarstatistics.ca.gov/, last visited March 15, 2016. In 2014 there were 13.3 million electric customers in California, according to Energy Information Administration data.

[22] RUCO Huber, at p. 1.

[23] APS 2014 IRP, at Attachment F.1(a)(4).

[24] Crossborder APS Study, TASC Exhibit 2, at pp. 9-10.

benefit. APS witness Brown appears to concede that renewable generation, with zero variable costs, will reduce wholesale market prices if it is produced in significant quantities. As noted above, renewable DG is now a significant resource in many states, including Arizona.

Q17: Mr. Brown claims that the concept of market price benefits represents a distortion of energy markets because renewables are "highly subsidized" in comparison to other energy resources. He cites federal tax credits, REC/SREC markets, and "the cross-subsidy inherent in net metering."[25] Please respond.

A17: All sources of energy are subsidized to a greater or lesser degree. This has been well documented in studies such as *What Would Jefferson Do? The Historical Role of Federal Subsidies in Shaping America's Energy Future* by Nancy Pfund and Ben Healey of DBL Investors (September 2011), which concludes that the subsidies received by the fossil fuel and nuclear industries have been far larger than those received by renewables.[26] Renewable DG does qualify for federal tax benefits, but there are no longer direct state subsidies in Arizona, and it is the conclusion of our updated benefit / cost study that net metering on the APS system does not represent an appreciable subsidy of DG today.[27] Further, the significant environmental benefits of DG (4.5 cents per kWh for carbon, health, and water benefits in our APS study), compared to the alternative of greater fossil generation, indicates clearly the extent to which the failure to internalize environmental costs in energy markets and utility rates represents a major subsidy of fossil energy, a subsidy paid by future generations to the present.

Q18: Please discuss grid services – a benefit of DG that other parties did not mention.

A18: Grid services are benefits of DG provided to the grid when DG is deployed with smart inverters and storage. These include voltage support, reactive power, and frequency support. In addition, by reducing loads on individual circuits, rooftop solar systems

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[25] APS Brown, at pp. 37-38.

[26] This study is available at http://insights.som.yale.edu/insights/should-government-subsidize-alternative-energy.

[27] Crossborder APS Study, TASC Exhibit 2, at pp. 1-4.

reduce thermal stress on distribution equipment, thereby extending its useful life and deferring the need to replace it. All of these additional, emerging values are difficult to quantify today, because there are not currently markets for these services, and utilities do not have an incentive to procure these types of services from third-party providers. However, they have the potential to become a significant benefit in the near future, and may offset some or all of the integration costs for these intermittent renewable resources.

Q19: APS attaches to its testimony a study on the economic impacts of distributed solar in Arizona, by the L. William Seidman Research Institute at Arizona State University (the Seidman Study). Please provide your critique of this study.

A19: The Seidman study calculates the economic impacts of distributed solar deployment based on future investment scenarios provided by APS. There are a number of manifest flaws in the scenarios that APS provided:

1. **No Avoided T&D Costs.** APS's scenarios assume that the widespread deployment of distributed solar generation, located at the point of end use, would have no effect on its future needs for or investment in the grid's delivery infrastructure.[28] This is despite the fact that solar DG can reduce the peak loads on the APS grid that drive long-term T&D investments, as shown in the Crossborder benefit/cost analysis for APS[29] and as recognized by many parties in their lists of the benefits of DG.

2. **Solar's Capacity Contribution Is Too Low.** APS assigns a capacity value of just 16.5% of nameplate to solar installed in 2016 (in the Medium case), with declining percentages in subsequent years. This capacity value is far too low, given that the utility's hourly load forecast for 2016 shows that the typical solar capacity factor over the utility's peak hours[30] is 36% for south-facing systems and 53% for west-facing. As a result of APS's too-low capacity value, the amount of future capacity additions that solar

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[28] See APS response to TASC Data Request 5.3.

[29] Crossborder APS Study, TASC Exhibit 2, at pp. 13-16.

[30] Defined as all hours with loads within one standard deviation of the peak hour load, with the each hour weighted by the increment between (1) that hour's load and (2) the threshold of one standard deviation below the peak hour. See Crossborder APS Study, TASC Exhibit 2, at p. 12.

can defer is significantly underestimated in the APS investment plan. This will be particularly true if, over time, west-facing installations and the use of distributed storage first mitigate and then reverse any decline in solar's capacity value.

3. Distributed Solar Costs Are Too High. APS's workpapers show that the utility has assumed that the federal ITC drops to 10% in 2017.[31] In fact, the 30% federal ITC has been extended at the 30% level through 2019, then declining to 26% in 2020, 22% in 2021, and 10% in 2022. As a result, additional solar investment in Arizona will benefit the state much more than the Seidman Study has estimated, because more of the costs of future solar deployment will be borne by taxpayers in other states. Further, APS uses a static estimate of future solar capital costs; the utility assumes that solar capital costs decline by just 1% per year from 2016-2035. This would be far slower than the solar cost declines of about 7% per year experienced in recent years as documented in the LBNL and NREL data shown below in the figures provided in response to Commissioner Little's Question No. 7.

Finally, a basic flaw in the Seidman study is its assumption that the value of a successful and growing distributed solar industry is measured solely by the industry's impact on APS, the local utility. Arizona, with its abundant solar resources, research universities that do significant solar research, and position in the heart of the U.S. Southwest, could be a hub for solar activity at all scales in the region, in the rest of the U.S., and in the world. In other words, the true upside for Arizona is not just the economic activity that the solar industry could generate by making electricity in APS's service territory, but the economic activity in Arizona related to providing solar services to the region, the U.S. and export markets. This upside potential is not at all considered in the Seidman Study.

[31] See APS response to Vote Solar Data Request 3.24. See the tab "*SEND – DE Costs*," Cell N2, showing the use of a 30% ITC in 2016 and 10% thereafter.

V. CONSIDER THE MULTIPLE PERSPECTIVES OF KEY STAKEHOLDERS

Q20: Why is it important for the Commission to consider the benefits and costs of DG from multiple perspectives?

A20: Traditionally, the Commission's role is to balance the interests of, first, ratepayers as a whole and, second, the utility and its shareholders. Customer-owned or customer-sited DG introduces a third key perspective – the participating ratepayers who make long-term investments in renewable DG. If a sustainable, innovative DG industry is to succeed in Arizona, the Commission must respect the long-term investments that tens of thousands of Arizona utility customers have made in renewable DG. As a result of the presence of this additional key stakeholder, the Commission cannot just consider a benefit/cost test (such as the RIM Test) that focuses only on non-participating ratepayers.

Q21: What is the most important perspective for the Commission to review?

A21: The TRC/Societal Tests consider the benefits and costs of renewable DG from the perspective of all ratepayers and the broader community as a whole. In these tests, the costs are the capital and operating costs of the new resource, while the benefits are the costs that the utility will avoid as a result of the output of the new resource as well as the societal and environmental benefits of these resources (in the Societal Test). This is the same perspective that the Commission uses to evaluate other demand-side energy efficiency programs (through the Societal Test) or to review utility-owned generation plants for reasonableness in ratemaking, certification, or resource planning cases. Mr. Brown for APS spends many pages of his testimony complaining that "value of solar" analyses do not treat DG on the same basis as other possible new resources.[32] If that is a concern of the Commission, the clear solution is to adopt the use of the Societal Test as the primary means to evaluate DG in ratemaking and resource planning cases. This would evaluate the cost-effectiveness of DG on the same basis as this Commission evaluates the cost-effectiveness of other types of both demand- and supply-side resources.

[32] APS Brown, at 15-18 and 60.

Q22: RUCO's witness Mr. Huber acknowledges that the Commission evaluates energy efficiency resources using the Societal Test, yet he recommends that the RIM test should be emphasized in ratemaking proceedings that impact demand-side DG resources.[33] He bases this recommendation on an assertion that DG has certain differences from energy efficiency. Please comment on these differences.

A22: His first and last points are that solar PV is less accessible to a broad range of customers than energy efficiency measures, and thus the benefits of solar PV to participants are concentrated in a smaller group of customers. APS witness Mr. Brown repeatedly makes the same point in a more pointed fashion, suggesting that, because rooftop solar allegedly is adopted mostly by higher-income individuals, it has a "regressive social impact."[34]

First, this point ignores the significant progress that the solar industry has achieved, as a result of solar leasing and power purchase agreement programs, in making rooftop solar accessible to middle-income Americans. For example, in California, one of the goals of the California Solar Initiative was to make rooftop solar a mainstream energy choice. Significant progress toward that goal has been achieved – since 2014, more than half (53%) of the rooftop solar installed in California has been deployed by homeowners living in zip codes where the median owner-occupied income is $55,000 to $70,000 per year.[35] These are certainly middle class customers. The way to sustain this progress is to continue to bring distributed solar to scale. The way forward is <u>not</u> to adopt a regulatory framework that unreasonably requires solar customers again to pay a significant premium in their overall cost of electricity if they adopt solar, as unfortunately has occurred in Nevada and in the Salt River Project's service territory. Such a result simply would turn back the clock so that only the truly wealthy could afford solar.

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[33] RUCO Huber, at pp. 10-12.

[34] APS Brown, at p. 24 and 46-47.

[35] See the Kevala Analytics white paper on the income distribution of rooftop solar customers. Available at http://kevalaanalytics.com/wp-content/uploads/Kevala-CA-Residential-Solar-Income-Analysis.pdf.

Second, the means to make solar accessible to renters, customers whose homes are shaded, or lower-income customers is through programs targeted at these customers, such as community solar and programs for disadvantaged communities. I encourage the Commission to consider the targeted solar programs that other states have adopted:

- Massachusetts has a successful program of remote or virtual net metering, whereby centralized solar installations can earn net metering credits at small commercial rates, and can assign those credits to subscribing customers at different locations in the same community.[36]

- California has targeted subsidy programs to install solar on both low-income single- and multi-family homes, and is developing a new net metering program in disadvantaged communities.[37]

- Other states are pursuing a wide range of community solar models.[38] In order to allow for the greatest amount of innovation, the Commission should consider community solar programs where the shared solar development opportunity is open to all types of entities – utilities, public agencies, and private developers.

Third, more generally, the U.S. has a capitalist economy that is the most innovative in the world. The way that technological innovations are diffused in our economy is typically that they are initially expensive, and available only to higher-income consumers or enthusiasts, until they can be brought to scale. This is a pattern that has been repeated from the automobile to televisions to personal computers to cell phones to smart phones, and now to solar systems and electric vehicles. Mr. Brown's complaint that rooftop solar has a "regressive social impact" echoes the complaints made by socialists and buggy-owners in the early 1900s about the first new-fangled automobiles

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[36] See, for example, National Grid's description of its Massachusetts net metering programs https://www9.nationalgridus.com/masselectric/home/energyeff/4_net-mtr.asp.

[37] See the California Single-family Affordable Solar Homes (SASH) and the Multi-family Affordable Solar Homes (MASH) programs, at http://www.cpuc.ca.gov/General.aspx?id=3043 and https://www.pge.com/en/mybusiness/save/solar/mash.page. Also, see CPUC Decision No. 16-01-040, at pp. 37-42, 101 and 103 for a discussion of the Disadvantaged Communities program.

[38] For a listing of community solar projects, see https://www.communitysolarhub.com/. Also see the Interstate Renewable Energy Council's work on shared renewables, at http://www.irecusa.org/regulatory-reform/shared-renewables/. For different community solar models, see http://www.seia.org/policy/distributed-solar/shared-renewablescommunity-solar.

owned by the wealthy.[39] His complaint suggests that his remedy would be for the government to intervene so that its regulated proxy, the utility, would dole out a limited number of utility-owned rooftop solar systems to customers by lottery. This clearly would not be the best path, or the American way, to foster innovation and scale in a promising clean energy technology.

Q23: Mr. Huber also argues that DG has different impacts on the utility system than energy efficiency. For example, he argues that solar DG has "less diverse" impacts than energy efficiency, and that solar DG merely "masks" end use loads, rather than reducing them completely. He also notes that integrating solar resources can increase utility costs.[40] Are these valid reasons why DG should be judged by a different standard than other types of resources?

A23: No. As Mr. Huber admits, energy efficiency and demand response measures also have diverse impacts on the grid – some predominantly reduce baseload energy use (like more efficient refrigerators), while others moderate peak demand (like high efficiency air conditioners). Just as the different characteristics and benefits of various EE and DR resources are modeled in the Societal Test, so too can the impacts and benefits of solar DG be analyzed based on its own attributes. With respect to solar DG only "masking" the loads it serves, this effect is small, given the large number of DG systems, their low forced outage rates, and the fact that they do not all fail at once.[41] Moreover, the same uncertainty is also present for EE and DR resources. It is well-known that EE resources exhibit a "rebound effect," whereby a portion of the benefits of an EE measure are eroded by the greater use of the more efficient device, compared to the less-efficient one. Similarly, the utility cannot be certain of the exact number of DR customers that will respond to reduce demand when called upon to do so. With respect to the impacts of

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[39] See Gartman, David, *Auto-Opium: A Social History of American Automobile Design*, at pp. 36-37.

[40] RUCO Huber, at pp. 11-12.

[41] For example, if 10,000 DG systems with an average size of 10 kW (100 MW total) have a forced outage rate of 1%, on average just 100 units will be out of service at any one time, and the average additional load that has to be served is just 1 MW. This is far easier for the system to handle than the sporadic outages of a 100 MW generator, which requires that an additional 100 MW of generation be available to replace it when it is out.

solar DG on increasing the costs to manage the grid, such as the impacts on ramping and regulation requirements, these effects are also produced by utility-scale solar generation, and integration studies can delineate the costs associated with these impacts. Generally, as noted in our APS Study, integration costs are small at the current penetration of solar resources.[42] I agree that these integration costs should be included in benefit/cost analyses of solar DG, based on the wealth of new information that is becoming available as control areas in the U.S. integrate larger amounts of variable renewable generation.

Q24: What should the role of the RIM Test be in the Commission's evaluation of renewable DG?

A24: The Commission should use the Participant and RIM Tests to ensure that there is an equitable balance of costs and benefits between those ratepayers who install DG systems and those who do not. The Participant and RIM Tests are the opposite sides of the same coin, as shown in **Table 1** of my direct testimony. The primary <u>benefits</u> of DG for participating ratepayers in the Participant Test are bill savings; in the RIM Test, these bill savings are the primary <u>costs</u> of DG for non-participating ratepayers, i.e. the utility's lost revenues. By looking at both perspectives, and ensuring that both tests yield results that are reasonably close to 1.0, the Commission can ensure that renewable DG remains a viable choice for Arizona ratepayers without presenting an undue burden on ratepayers who do not exercise this competitive option. By finding this balance, the Commission will best serve the public interest of all ratepayers in Arizona.

[42] Crossborder APS Study, TASC Exhibit 2, at p. 23. As another example from another region, *see* the 2014 integration study for Duke Energy, *Duke Energy Photovoltaic Integration Study: Carolinas Service Areas* (Battelle Northwest National Laboratory, March 2014), at Table 2.5 and Figure 2.51. This study calculates that, with 673 MW of solar PV capacity on the Duke utility systems in 2014, integration costs would be about $0.0015 per kWh.

VI. RESPONSES TO COMMISSIONER'S QUESTIONS

A. Commissioner Little

1. How were the value and cost of solar considered in the development of the current net metering tariffs?

Response: As noted in the testimony of Vote Solar's witness Kobor, the Commission's Decision 69127 adopted net metering tariffs and found that renewable DG would provide benefits ("value") including reducing peak period costs for generation (both energy and capacity), as well as decreasing loads and avoiding costs on the transmission and distribution systems.[43]

2. Over the past several years the cost of PV panels has declined significantly. Does the declining cost of panels affect the value proposition? If so, how?

Response: In recent years, the declining cost of panels has allowed the solar industry to maintain the value proposition for customers even as many direct state incentives have been reduced to zero, including in Arizona. The capital cost of solar equipment is the primary cost of solar DG to participating customers and is a principal cost in the Participant Test. As shown in the Participant Test results in our updated benefit / cost study for APS, the current cost of solar for participating residential solar customers (17 c/kWh) is in balance with the bill savings realized by these customers (17.9 c/kWh).[44]

3. Is it appropriate to factor the cost of the panels into the reimbursement rate for net metering? If so, how?

Response: As discussed above, the Commission should ensure that there is an equitable balance between participating and non-participating customers. This balance appears to exist today in the residential market, with the current net metering rules and the existing retail

[43] Decision 69127, at Appendix B, page 6, Proposed Rulemaking for the Renewable Energy Standard and Tariff Rules, No. RE-00000C-05-0030 (Ariz. Corp. Comm'n, Nov. 14, 2006), Barcode No. 0000063561.

[44] Crossborder APS Study, TASC Exhibit 2, at Table 1, p. 3.

rate structure. The interests of participating solar customers are measured by the results of the Participant test, in which the cost of panels is the principal cost. If net metering is changed, or rates are restructured, such that the bill savings for solar customers are reduced significantly, the economics of renewable DG will no longer support customer adoption of these technologies.

4. Does the cost and value of DG solar vary based on the specific customer location? Should this variability be reflected in rates?

Response: The cost and value of DG solar can vary by location as the result of many factors, including the quality of the solar resource, whether the distribution system is constrained, the line losses avoided, and the location of the customer on the state's transmission grid. Developing locational costs and values is a complex undertaking, and could require locational marginal pricing (LMP) on the grid in Arizona and the development of distribution resource plans (DRPs) by the Arizona utilities, similar to the plans now under development by utilities in New York and California. Unless LMPs and DRPs are developed in Arizona, it may be difficult to assemble the information that would be needed to reflect this locational variability in rates.

5. How does the cost and value of DG solar vary based on the orientation of the panels? How would the installation of single or dual access trackers change the output or efficiency of the DG solar system? Should this variability be reflected in rates?

Response: As shown in the Crossborder APS Study, west-facing panels have significantly higher capacity value than south-facing, because the output of west-facing systems peaks later in the afternoon and thus coincides more closely with the peak loads that drive capacity costs for both generation and T&D. The same is true of the use of tracking. The west-facing siting of panels and the use of tracking can be encouraged through the increased use of TOU rates. To increase awareness of the higher benefits of west-facing systems and to offset the lower annual production of west-facing panels, the Commission should consider direct upfront incentives for west-facing systems, just as incentives are used to overcome market barriers to customer uptake of energy efficiency measures.

6. How is the value and cost of DG solar affected when coupled with some type of storage? Should deployment of storage technologies be encouraged? If so, how?

Response: The value of solar can be increased significantly when paired with storage. For example, the generation and T&D capacity value of solar alone is 20% to 55% of nameplate. These percentages can be increased significantly, perhaps to 80% or more, by using storage to shift peak solar output by a few hours so that it coincides with the times of peak loads at both the system and distribution levels. Storage also can provide ancillary services and increase the reliability and resiliency of electric service to critical loads. However, storage presently is expensive, and requires financial and policy support to be economic and to be brought to scale. In 2013, California adopted a storage portfolio standard with a goal of 1.325 GW of storage installations by 2020,[45] supported through utility storage RFOs and incentives for distributed storage available through the state's self-generation incentive program (SGIP).[46] Importantly, at least 50% of the available storage capacity will be developed and owned by third-parties, to stimulate a diverse and competitive market for storage.[47] The Commission should consider comparable programs to incent storage development in Arizona.

Storage paired with solar also can serve electric loads without the use of the grid, and such grid defection will become increasingly economic as distributed storage costs decline with increasing scale. In my opinion, significant grid defection would be an unfortunate result, because the combination of grid-connected solar plus storage can offer significant benefits to all customers. Grid defection can be minimized with reasonable pricing and incentives for grid-connected solar DG that balance the interests of both

45 See http://www.greentechmedia.com/articles/read/california-passes-huge-grid-energy-storage-mandate.

46 Information about California's electric storage mandate and SGIP program are available at http://www.cpuc.ca.gov/general.aspx?id=3462 and http://www.cpuc.ca.gov/general.aspx?id=5935.

47 See CPUC Decision No. 13-10-040, at pp. 51-52. Available at http://www.cpuc.ca.gov/general.aspx?id=5935.

participating and non-participating consumers. This is also the conclusion of a recent major study of the economics of grid defection throughout the U.S.[48]

7. How does the value and cost of DG solar compare to the value and cost of community scale and utility scale solar? How do the value and costs of DG solar compare to that of wind or other renewable resources? How does the value and cost of DG solar compare to that of energy efficiency?

Response: As discussed above and in my direct testimony, solar and wind DG provide a retail product that is delivered directly to loads. This is a fundamentally different product than the wholesale power provided by utility-scale solar plants or wind farms whose output must be delivered by the utility. Any economic comparison of DG to utility-scale generation must consider the costs required to deliver the utility-scale generation to loads. Further, although utility-scale solar is less expensive than DG solar due to economies of scale, the cost difference between these resources has narrowed in recent years, as shown in the following figures from Lawrence Berkeley National Lab's (LBNL) reports tracking solar costs. The first figure shows median utility-scale solar costs averaging $2.30 per watt-DC in 2014.[49]

[48] See Rocky Mountain Institute, *The Economics of Grid Defection* (April 2015), available at http://www.rmi.org/electricity_grid_defection.

[49] From Mark Bolinger and Joachim Seel, *Utility-Scale Solar 2014: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States* (LBNL, September 2015). Available at https://emp.lbl.gov/sites/all/files/lbnl-1000917.pdf.

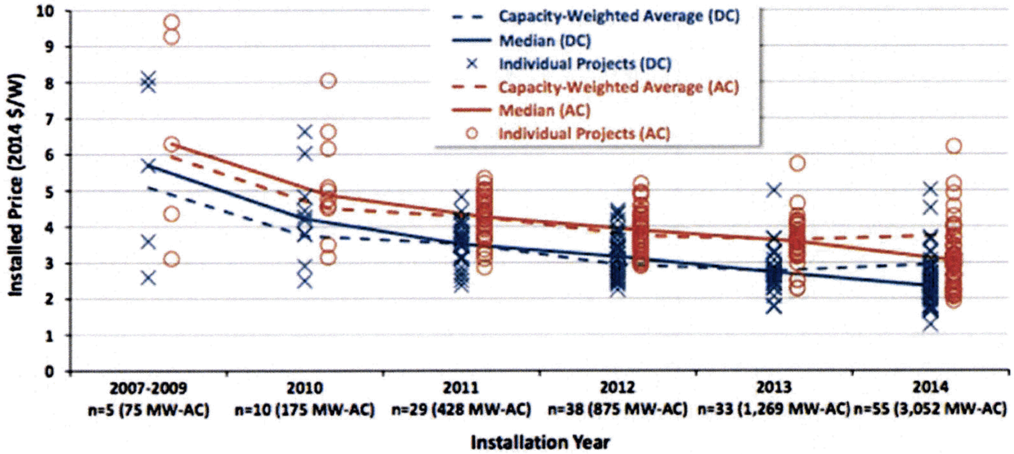
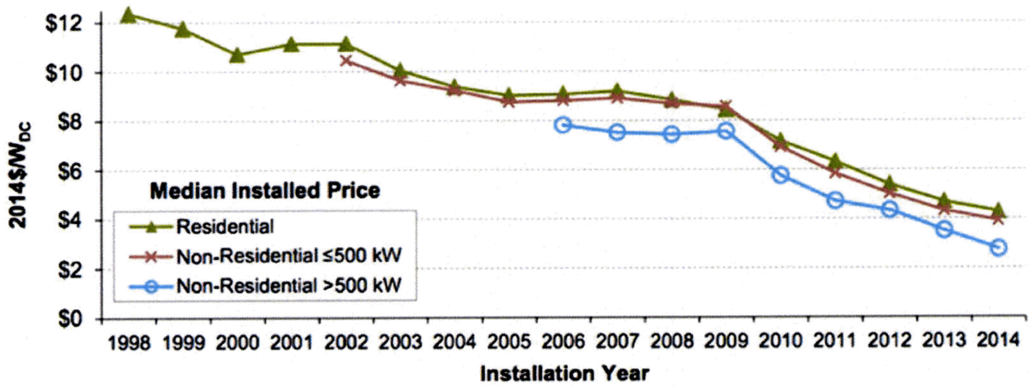


Figure 6. Installed Price of Utility-Scale PV and CPV Projects by Installation Year

The second figure presents rooftop solar costs.[50] The costs of large commercial rooftop arrays (> 500 kW) reached $2.40 per watt-DC in 2014, very close to utility-scale solar costs at $2.30 per watt-DC. Smaller rooftop projects averaged about $4.00 per watt-DC. These charts show that, since 2007, the cost difference between small rooftop and utility-scale solar systems has narrowed from $3.50 per watt-DC in 2007-2009 to $1.70 per watt-DC in 2014. This narrowing of the cost difference between rooftop and utility-scale solar projects is due in significant part to reductions in the soft costs of rooftop installations.

[50] From Galen L. Barbose and Naïm R. Darghouth, *Tracking the Sun VIII: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States* (LBNL, August 2015). Available at https://emp.lbl.gov/sites/all/files/lbnl-188238_2.pdf.



Notes: See Table 1 for sample sizes by installation year. Median installed prices are shown only if 20 or more observations are available for a given year and customer segment.

Figure 7. Median Installed Price Trends over Time

8. How does the intermittent nature of DG solar affect its value and costs? Are there technologies that could reduce the intermittency of DG solar? Should those additional costs result in changes to the value and cost of DG solar? Should an "intermittency factor" be applied to more accurately determine cost and value?

Response: The capacity value of solar DG used in benefit / cost studies recognizes the intermittent nature of solar output. There are well-accepted methods for calculating the capacity value of solar and wind given their intermittency (see, for example, the Peak Capacity Allocation Factor method used in the Crossborder APS Study, at pages 12-13 and 16). In addition, integration cost studies calculate the cost impacts of operating the grid with a higher penetration of intermittent wind and solar resources. The use of distributed storage definitely would reduce the intermittency of DG solar, and will increase its value.

9. To what degree is DG solar energy production coincident with peak demand? Does the cost and value of DG solar vary depending on whether or not energy production is coincident with peak demand? Are there policies that the Commission could consider that address this issue?

Response: Solar output is partially but not completely coincident with peak demand. This partial coincidence is fully considered in the methods used to value the capacity provided by solar resources. The analyses in the Crossborder APS Study determined that the capacity value of solar in Arizona ranges from 20% to 55% of nameplate capacity, depending on the orientation of the array and the customer class served.[51] As discussed above, the Commission could increase the capacity value of solar significantly by incenting west-facing systems and distributed storage.

10. Is it possible for DG solar to be more dispatchable? How does the ability to dispatch or the lack of ability to dispatch affect the value and cost of DG solar?

Response: Yes. Technologies such as smart inverters and storage can enable solar (or the loads which solar serves directly) to be more dispatchable. These technologies will increase the value of solar significantly, and mitigate the erosion of solar's capacity value as its penetration increases.

11. Will the bi-directional energy flow associated with DG solar require modifications or upgrades to the distribution system? How should the cost of these upgrades be considered when determining the cost and value of DG solar? Would the required upgrades vary based on location and penetration of DG solar? Should the costs for DG installations vary based on these factors?

Response: Significant distribution system modification or upgrades will be necessary only at far higher penetrations of solar DG than Arizona is now experiencing. Experience in Hawaii, where solar penetration is approaching 20% of all customers, shows that distribution systems can accommodate significant exports from high penetrations of solar DG facilities, at levels above even the minimum daytime distribution system load, without charging DG customers for ongoing costs beyond those identified through the interconnection process.[52] Arizona is presently at about one-sixth the level of DG penetration that Hawaii is experiencing. APS has stated in discovery that it has not incurred significant costs today to accommodate exports from DG projects, even when

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[51] Crossborder APS Study, TASC Exhibit 2, at pp. 12-13 and 16.

[52] For example, the Hawaiian Electric Company (HECO) maintains public "locational value maps" of its distribution system which show the amount of interconnected DG on each circuit, as a percentage of the circuit's peak load and its minimum daytime load. Many circuits have DG capacity in excess of 120% of the daytime minimum load, which means that the circuit is likely to backfeed to upstream portions of the system. *See* https://www.hawaiianelectric.com/clean-energy-hawaii/integration-tools-and-resources/locational-value-maps.

these exports cause isolated instances of reverse flow on its residential distribution feeders.[53]

12. How much should secondary economic impacts of DG solar deployment be considered in the value and cost considerations? Do investments in other types of generation technology have similar, greater or lesser secondary economic impacts? If so, how?

Other impacts to consider include:

a. Job impacts associated with DG solar installations;
b. Job impacts associated with closure of fossil fuel plants (and mines) displaced by DG solar;
c. Distribution of DG solar economic benefits between DG installers, customers who install DG solar, PV panel manufacturers and others;
d. Impact of DG solar deployment on overall energy costs and those costs' impacts on economic activity;
e. Effect of DG solar deployment on natural gas and coal prices; and
f. Opportunity costs associated with incenting DG solar, e.g., funds spent on DG solar cannot be spent on other renewable energy resources or energy efficiency.

Response: The secondary economic impacts of DG solar deployment are varied, and can be estimated in certain respects. Solar DG will reduce market prices for natural gas and wholesale power, and these direct benefits for ratepayers are estimated in the Crossborder APS Study, at pages 10-11. This estimate does not include the broader economic benefits of these price reductions. The Crossborder APS Study also estimates, at pages 20-21, the increased local economic activity in the community where the solar DG is located, as a result of the installation of renewable DG. The concept of "opportunity costs associated with incenting DG solar" assumes that Arizona ratepayers are subsidizing DG solar. However, there are no longer direct state incentives for DG solar, and it is our conclusion, based on the Crossborder APS Study, that net metering in Arizona does not represent an appreciable subsidy today. Furthermore, the capital costs for solar DG are paid for or supported by customers themselves and by federal tax credits, not through financing by the utility. This represents new sources of capital for building clean energy infrastructure in Arizona. Finally, the fact that renewable DG produces a net benefit in the TRC and

[53] See APS response to TASC Data Request 4.4.

Societal Tests means that it is likely to result in a net economic benefit for the state of Arizona.

13. How does the value and cost of DG solar change as penetration levels rise? How should this be considered in rate making and resource planning contexts?

Response: The <u>cost</u> of DG solar should continue to fall as penetration increases. The <u>value</u> of DG solar (in terms of its ability to defer capacity) may decrease as penetration increases; for example, if peak loads shift to later in the afternoon. However, this drop in benefits can be offset or reversed by greater use of west-facing or tracking systems and the increased use of distributed storage. See the responses to Questions 5, 6, 9, and 10 above for suggestions for incentives to encourage such innovations.

14. Should the fuel cost savings to the utility associated with DG solar be considered in the value and cost determination? If so, how do we deal with the uncertainty of future fuel prices?

Response: Fuel cost savings to the utility associated with DG solar are an integral part of the benefits of DG solar. See Crossborder APS Study, at pages 8-10. One means to deal with the uncertainty in future fuel prices is to use forward natural gas prices and hedging costs, which represent the costs to the utility to minimize the future volatility in its natural gas costs. Alternatively, high, low, and base scenarios for future fuel prices can be examined.

15. Does the deployment of DG solar result in changes in the need for transmission capacity? If so, how should those changes be included in the value and cost considerations?

Response. Yes, DG solar will reduce the future need for transmission capacity, in conjunction with other demand-side resources such as energy efficiency and demand response. The marginal cost of transmission capacity can be estimated, or the proxy of the utility's current FERC-regulated long-term wholesale firm transmission rate can be used (see Crossborder APS Study, at pp. 13-15).

16. Does the deployment of DG solar result in changes in the need for distribution capacity? If so, how should those changes be included in the value and cost considerations?

Response. Yes, DG solar will reduce the future need for distribution capacity, again in conjunction with other demand-side resources such as energy efficiency and demand response. Marginal distribution costs can be calculated (see Crossborder APS Study, at pp. 15-16). More broadly, I anticipate that there will be many beneficial reasons in the future for utilities to upgrade and to modernize their distribution grids. Integrating DG is just one of these. Others include:

1. Reducing the effects of outages;
2. Improving workforce and asset management;
3. Reduced costs for distribution maintenance;
4. Greater visibility for system operators into local grid conditions;
5. Reduced response times to customer outages;
6. Development of a charging infrastructure for electric vehicles;
7. Opportunities to reduce stationary source air emissions through further electrification of buildings and industrial processes; and
8. Allowing deployment of distributed storage, which in turn has numerous potential benefit streams – energy arbitrage, capacity deferral, ancillary services, enhanced reliability and resiliency, and power quality.

There is significant potential for the intelligent deployment of DG to reduce the costs associated with grid modernization. Solar City recently released an important white paper, *A Pathway to a Distributed Grid*, which quantifies the net benefits of distributed energy resources ("DER") – including both DG and other distributed resources such as smart inverters, storage, energy efficiency, and controllable loads – and shows that they are a cost-effective approach to grid modernization. This study reviews the recent grid modernization proposal of Southern California Edison, and concludes that only 25% of the proposed investments are related to DER integration. The other 75% are intended to realize the other benefits listed above.[54]

[54] This Solar City white paper is available at http://www.solarcity.com/sites/default/files/SolarCity_Distributed_Grid-021016.pdf.

17. Does the grid itself add value to DG solar? If so, how should the value of the grid be considered when assessing the value and cost of DG solar?

Response: Yes, the grid adds value to DG solar, and DG solar adds value to the grid. Both should be considered. As discussed in my direct testimony, a DG customer pays for the value that the grid adds whenever the customer's meter runs forward. The DG customer pays the same retail rate that all other customers pay for the grid's valuable services. A regular, non-DG customer can spike a demand on the grid when the air conditioner is turned on, just as a solar customer may spike a demand on the grid when a cloud comes overhead. Both customers pay the same amount for this grid service by running the meter forward at the retail rate.

18. Does the deployment of DG solar result in a reduction in the use of water in electric generation? How should this be considered when determining DG solar value?

Response: Yes, there are important water-saving benefits from renewable generation. These benefits are discussed and calculated in the Crossborder APS Study, at pp. 19-20.

19. Are there disaster recovery or backup benefits associated with the deployment of DG solar? Are they reliable and quantifiable enough to determine tangible benefits that might accrue to the grid?

Response: Yes, although these benefits are challenging to quantify today. Renewable DG resources are installed as thousands of small, widely distributed systems and thus are highly unlikely to fail at the same time. Furthermore, the impact of any individual outage at a DG unit will be far less consequential, and less expensive for ratepayers, than an outage at a major central station power plant.[55] DG is located at the point of end use, and thus also reduces the risk of outages due to transmission or distribution system failures. One study of the benefits of solar DG has estimated the reliability benefits of DG from a national perspective.[56] The study assumed that a solar DG penetration of 15% would

[55] California has recent experience with the costs of such an outage – the prolonged and expensive shutdown and eventual closure of the San Onofre Nuclear Generating Station as a result of a design flaw in the replacement steam generators.

[56] Hoff, Norris and Perez, *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania* (November 2012), at Table ES-2 and pages 18-19.

reduce loadings on the grid during peak periods, mitigating the 5% of outages that result from such high-stress conditions. Based on a study which calculated that power outages cost the U.S. economy about $100 billion per year in lost economic output, the levelized, long-term benefits of this risk reduction were calculated to be $20 per MWh ($0.02 per kWh) of DG output. This calculation does not necessarily assume that the DG is located behind the customer's meter, so this reliability benefit also might result from widely distributed DG at the wholesale level.

However, most electric system interruptions do not result from high demand on the system, but from weather-related transmission and distribution system outages. In these more frequent events, renewable DG paired with on-site storage can provide customers with an assured back-up supply of electricity for critical applications should the grid suffer an outage of any kind. This benefit of enhanced reliability and resiliency has broad societal benefits as a result of the increased ability to maintain business, institutional, and government functions related to safety and human welfare during grid outages.

Both DG and storage are essential in order to provide the reliability enhancement that would eliminate or substantially reduce these interruptions. The DG unit ensures that the storage is full or can be re-filled promptly in the absence of grid power, and the storage provides the timely alternative source of power when the grid is down. DG also can supply the some or all of the on-site generation necessary to develop a micro-grid that can operate independently of the broader electric system. As a result, it is difficult to estimate the share of these reliability benefits that should be assigned to solar DG alone. Nonetheless, renewable DG is a foundational element necessary to realize this benefit – in much the same way that smart meters are necessary infrastructure to realize the benefits of time-of-use rates, dynamic pricing, and demand response programs that will be developed in the future. Accordingly, the reliability and resiliency benefits of wider renewable DG deployment should be recognized as a broad societal benefit.

20. What, if any, costs are associated with the utility providing voltage support and/or frequency support or other ancillary services in support of DG solar installations?

Response: If these costs exist today, they are small. Integration studies have calculated the increased regulation and ramping ancillary service costs associated with higher penetrations of intermittent renewable resources. These costs are likely to be offset in the future as smart inverters provide voltage and frequency support on the distribution system and as distributed storage provides ancillary services.

B. Commissioner Stump

1. The Commission's May 7, 2014 Workshop on the Value and Cost of Distributed Generation included debate on whether a remote solar generation station should receive equal treatment with rooftop solar, with regard to calculating the value of solar. What are the parties' thoughts?

Response: Solar and wind DG provide a retail product that is delivered directly to loads, a fundamentally different product than the wholesale power provided by remote utility-scale solar plants or wind farms whose output must be delivered by the utility. See Section VII of my direct testimony and the response to Commissioner Little's Question 7 above.

2. Why argue that a value-of-solar proceeding is important only for resource-planning purposes, given that discussions about cost-shifts are informed by discussions on the value of DG?

Response: Understanding the benefits and costs of renewable DG is important for ratemaking as well as resource planning cases. See Section VI of my direct testimony.

3. In 2014, lost fixed costs associated with EE programs amounted to $24.1 million out of $34.5 million in total cost shifts. Do recoverable EE lost fixed costs constitute a greater proportion of the total lost fixed cost revenue at hand? Discuss how value-of-solar discussions are informed by comparing the impacts of solar versus EE on the grid. Is the per-customer shift larger for solar versus EE customers? Why is the greater customer accessibility of EE programs relevant to this discussion? How does the average DG user's demand curve differ from an EE user, and describe its effect on the grid, given that the EE user is not in need of backup power, unlike the solar DG user.

Response: As cited by Commissioner Stump, the lost revenues associated with EE are significantly greater than for DG, at current levels of penetration. The lost revenues per customer may be lower for EE than for DG, but many of the impacts of EE and DG on the grid are similar, and can be evaluated with the same benefit / cost analyses. See the response to Q&A No. 21 above.

4. How do we calculate regressive social costs into the value of solar, given that non-solar utility customers subsidize solar customers?

Response: I disagree that there are "regressive social costs" from the deployment of a new technology such as DG, or that non-solar customers subsidize solar customers. The fact that new technologies are first adopted by wealthier individuals is how our innovative, capitalist economy works, as discussed in response to Q&A No. 20 above. The best means to ensure that renewable DG becomes a resource available to all utility customers is to continue to grow its scale, increase its penetration, reduce its cost, and adopt programs that make solar and other renewables available to renters, homeowners with shaded homes, and lower income families and communities.

5. Are solar DG users being overcompensated or undercompensated for remitting excess solar power to the utility at the retail rate?

Response: Based on the results of the Crossborder APS Study, solar DG users are being compensated at the right level today for remitting excess solar power to the utility at the retail rate. As stated in my direct testimony, if the Commission finds that it is necessary to adjust the balance of the interests between participating and non-participating ratepayers, the Commission can do so through rate design. The types of changes that the Commission should prioritize are those that align rates more closely with utility costs, such as time-of-use rates, or that continue to allow the greatest scope for customers to exercise the choice to adopt DG, such as a minimum bill. Fixed charges, demand charges, or rate design changes that apply only to DG customers should be avoided, due to problems with customer acceptance, undue discrimination, and the future potential for customer bypass of the utility system.

6. To what degree do intermittency and non-dispatchability affect the value of solar?

Response: See the responses to Commissioner Little's Questions 8, 9, and 10 above.

7. How will increases in productivity be incentivized once the value of solar is estimated? In addition to the declining cost of panels, is it appropriate to factor relatively high U.S. installation costs into a value-of-solar determination?

Response: A portion of the cost reductions achieved for solar DG in recent years has been from reductions in the "soft costs" that have been the primary reason why U.S. solar prices are higher than those in other markets such as Germany.[57] See the responses to Commissioner Little's Questions 2, 3, and 7 above.

8. In value-of-solar discussions, are we attributing a unique value to DG, which other power sources also have? In other words, are there alternatives to DG that may be more efficient in reaching the same desired outcome of reducing carbon dioxide emissions at lower instillation costs? How does the cost and value of DG compare with alternative renewable resources? In pursuing DG, what alternative forms of renewable energy are we displacing? How does the cost and value of DG compare with that of utility-scale and community-scale solar? Is DG as efficient as alternative forms of solar? Is the value of solar lessened for DG versus utility-scale or community-scale solar?

Response: Evaluating solar DG on the same basis that other demand- and supply-side resources are evaluated, using the TRC/Societal Tests, would be a good first start in comparing DG with other renewable and fossil resources on a level playing field. Such analyses also must recognize that solar DG provides a retail product that is different than the wholesale product supplied by utility-scale resources. See Section VII of my direct testimony and the response to Commissioner Little's Question 7 above.

9. How should we go about attempting to quantify largely externalized and unmonetized factors, such as projected financial, energy security, social, and environmental benefits? How are long-term forecasts accurately incorporated into present value-of-solar calculations?

Response: These factors should be quantified to the extent we are able to do so. A failure to quantify them implicitly assigns a value of zero to these factors, an assumption that clearly is wrong. These values should inform the Commission's deliberations on the right balance between stakeholders. See the Crossborder APS Study, at pages 17-21 discussing and quantifying the carbon, health, water, and local economic benefits of solar

[57] J. Seel, G. Barbose, and R. Wiser, *Why Are Residential PV Prices So Much Lower in Germany than in the U.S.: A Scoping Analysis* (LBNL, February 2013).

DG, as well as the response to Commissioner Little's Question 19 above, discussing the reliability and resiliency benefits of solar DG. Long-term forecasts should start with the utility's most recent resource plan, and should reflect input from a broad range of parties.

10. Despite recognized advantages, a number of states are reexamining their traditional net metering policies and underlying rate designs. The increasingly pervasive review of conventional net metering policies by states is attributable to a multitude of trends, including decreasing solar rebate incentives, rapid encroachment of renewable portfolio standards, the realization of net metering caps, as well as raised public awareness surrounding prospective cost-shift concerns.

For instance, the Hawaii Public Utilities Commission brought an end to the state's net metering program when it cut payments to new solar customers by approximately half the going rate.[58] Nevada alternatively reduced payments to existing solar customers from the retail to the wholesale rate and raised customers' fixed charges to cover the cost of using the grid.[59] Moreover, the California Public Utilities Commission recently approved a NEM 2.0 successor tariff, which effectively preserves retail rate payments for residential DG systems while imposing new interconnection fees, non-bypassable charges, and a shift to time-of-use rates for DG customers.[60]

a. Given this context, how did Hawaii, Nevada, and California value the costs and benefits of net-metered solar?

b. What analyses on the cost of solar did these states use when they changed their net metering policies in light of an acknowledged cost-shift? Did such analyses adequately account for the costs associated with redesigning and maintaining the distribution system to accommodate DG?

c. How would a value-of-solar methodology facilitate the successful implementation of similar updated policies in Arizona?

Response: Of the three states, California was the only one whose net metering docket considered benefit / cost analyses of solar DG from all of the key perspectives: participant, non-participant, and all ratepayers/society as a whole. These analyses were provided by the parties through the common "Public Tool" spreadsheet tool developed by

[58] Decision No. 33258, Docket No. 2014-0192 (Haw. Pub. Utils. Comm'n Oct. 12, 2015).

[59] Document IDs 8412 & 8414, Docket Nos. 15-07041 & 15-07042, (Nev. Pub. Utils. Comm'n Dec. 23, 2015).

[60] Decision No. 16-01-044, Docket No. R.14-07-002 (Cal. Pub. Utils. Comm'n Jan. 28, 2016).

the California Commission, which all parties in the CPUC's net metering docket were required to use.

Nevada relied on a cost of service study performed by the utility, and did not comprehensively update a 2014 benefit / cost study which showed that the benefits and costs of net metering were reasonably well-balanced in that state. Nevada also did not evaluate the impacts of its new DG rates on the economics of participating solar DG customers in Nevada.

Hawaii is a special case whose unique circumstances must be recognized, including the island grids, the high existing penetration of solar DG, the state's extremely high electric rates due to the use of fuel oil as the marginal fuel, and Hawaii's goal of achieving 100% renewable electric generation. The Hawaii PUC revised its net metering policies without conducting a comprehensive benefit / cost study, finding that the new export rate and DG service options would reduce the impacts of net metering on non-participating customers, without quantifying the need for or extent of this change. Similarly, without undertaking a specific analysis of the solar market in Hawaii, the Hawaii commission concluded that its changes "offer compelling value propositions to customers who may choose to interconnect new DER systems" and thus "the interim options approved herein provide near-term balance, customer choice, and value to both participating and non-participating customers."[61] In replacing net metering, the Hawaii commission adopted an uncapped option for customers to self-supply their loads with DG, and a capped option that allows exports to the grid at a new, lower export rate. Hawaii will be conducting a more detailed analysis in Phase 2 of its DG proceeding.[62]

Q25: Does this conclude your prepared rebuttal testimony?

A25: Yes, it does.

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[61] Hawaii PUC Decision No. 33258 (Docket No. 2014-0192, October 12, 2015) , at pp. 166-167.

[62] *Ibid.*, at p. 167.

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE CHAIRMAN	BOB STUMP COMMISSIONER	BOB BURNS COMMISSIONER
TOM FORESE COMMISSIONER	ANDY TOBIN COMMISSIONER	

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION	**DOCKET NO. E-00000J-14-0023**

REBUTTAL TESTIMONY OF WILLIAM A. MONSEN

REBUTTAL TESTIMONY OF WILLIAM A. MONSEN
ON BEHALF OF THE ALLIANCE FOR SOLAR CHOICE (TASC)
(Docket No. E-00000J-14-0023)

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REBUTTAL TESTIMONY OF WILLIAM A. MONSEN
ON BEHALF OF THE ALLIANCE FOR SOLAR CHOICE (TASC)
(Docket No. E-00000J-14-0023)

I. Introduction and Summary of Testimony

Q. Please state your name, position and business address.

A. My name is William A. Monsen. I am a Principal at MRW & Associates, LLC (MRW). My business address is 1814 Franklin Street, Suite 720, Oakland, California.

Q. On whose behalf are you providing this testimony?

A. I am providing this testimony on behalf of the Alliance for Solar Choice (TASC).

Q. Please describe you background, experience and expertise?

A. I have been an energy consultant with MRW since 1989. During that time, I have assisted independent power producers, electric consumers, financial institutions, and regulatory agencies with issues related to power project development, project valuation, purchasing electricity, and regulatory matters. I have directed or worked on projects in a number of states and regions in the United States, including Arizona, Colorado, California, Nevada, New England, and Wisconsin. Prior to joining MRW, I worked at Pacific Gas and Electric Company ("PG&E"). At PG&E, I held a number of positions related to energy conservation, forecasting, electric resource planning, and corporate planning. I hold a Bachelor of Science degree in engineering physics from the University of California at Berkeley, and a Master of Science degree in mechanical engineering from the University of Wisconsin-Madison.

Q. Have you previously testified as an expert witness?

A. Yes. I have previously testified before the Commission on behalf of AES NewEnergy and Strategic Energy LLC. In addition, I have testified before the California Public Utilities Commission (CPUC) on behalf of the City of San Diego, the City of Long Beach, Bear Mountain, Snow Summit, the Independent Energy Producers Association, the California Cogeneration Council, Duke Energy North America, the Alliance for Retail Energy

Markets, the Center for Energy Efficiency and Renewable Technologies, the Local Governmental Commission Coalition, Clearwater Port, Commercial Energy, and The Vote Solar Initiative. I have also submitted testimony in proceedings before the Federal Energy Regulatory Commission as well as state utility commissions in Arizona, Colorado, Massachusetts, Oregon, and Nevada. Additional information about my qualifications is provided in Exhibit WAM-1.

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

A. My testimony reviews Arizona Public Service's (APS's) testimony related to the cost of service studies for Net Energy Metered (NEM) customers in the residential customer class.[1] Based on this review, I propose various changes to the underlying assumptions used in those cost of service study to correct APS's errors. Using these corrected assumptions, I develop corrected estimates of costs of service for APS's residential customers.

Q. How is your testimony organized?

A. Following this introduction, my testimony consists of five sections. Section 2 discusses why this proceeding is not the appropriate forum for consideration of Cost of Service Study (COSS) issues. Section 3 discusses why a COSS is the improper tool for evaluation of long-lived resource acquisitions. Section 4 addresses why the Commission should reject APS's proposal to create a new class for NEM customers. Section 5 summarizes APS's COSS, addresses the flawed assumptions related to the allocation factors used used by APS in its COSS, and presents TASC's recommended credits for NEM customers that should be applied to arrive at a net cost of service for NEM.

Q. Please summarize your recommendations and conclusions.

A. In its December 3, 2015 procedural order, the Commission requested that parties comment on the value and cost of solar, as well as the cost to serve customers both with and without distributed generation (DG). In response, APS chose to submit a COSS, in which APS claims that NEM customers currently pay far less than their cost of service

[1] In this testimony, all references to NEM customers relate to NEM customers in the residential customer class unless otherwise noted.

and proposes a dramatic restructuring of rates. However, this is a proceeding that is primarily concerned with the value and cost of DG; it is not a ratesetting proceeding. Thus, this proceeding is not the appropriate place to consider cost of service issues for specific utilities or to consider new rate proposals. Furthermore, APS's COSS contains clear flaws. The Commission should, therefore, note the flaws and issues raised by APS's COSS, but should delay making any final determinations regarding the COSS until APS's next general rate case.

Notwithstanding the fact that the Commission should not make any final determinations regarding APS's COSS in this proceeding, there are serious substantive shortcomings in APS's COSS in terms of its methodology and assumptions, making the APS COSS of little or no value to the Commission in its assessment of the value of solar.

First, APS's COSS simply ignores multiple aspects of DG value because APS has elected to view these new DG resources only on the basis of short-term costs and benefits. Since a COSS focuses on short-term cost issues, it is not the proper tool for evaluating new generation resources, whether they are traditional utility scale projects or DG. Any evaluation of DG resources must at least consider the potential value that is under consideration in this proceeding, such as potential avoided transmission and distribution capacity and accurate generation capacity and energy. The APS COSS simply assumes that NEM resources cannot avoid transmission or distribution costs. Therefore, APS's COSS provides little information about the long-run value of NEM resources. The Commission should give it no weight in assessing the long-run value of solar.

Second, APS recommends establishing a new customer class for residential customers who install DG systems and use NEM service. APS contends that NEM customers have different load shapes and different costs of service than other residential customers. Neither argument is persuasive. Although NEM customers may not have delivered load shapes that mimic those of the "average" residential customer, the same could be said for many other sets of customers that are currently in the residential customer class. By providing only a selective application of what APS means by "different load shapes" along with the fact that APS's COSS is unreliable, APS has met its burden of proof for establishing a new customer class. The Commission should refuse to approve this proposal in this docket.

Third, APS has used flawed assumptions in its COSS when it tried to calculate both the cost of service for NEM customers as well the credits against the cost of service related to the value of solar generation (the difference between the estimated cost of service and the estimated credits being equal to the "net cost of service." APS has two options for how to develop the net cost of service for NEM customers: to base its COSS on delivered energy or to base its net COSS on gross household load less credits for energy generated by NEM customers. APS chose the latter approach but then incorrectly calculated the benefits of NEM by failing to account for the capacity value of solar put onto APS's distribution system and by using the incorrect allocator for demand costs.

I demonstrate that by using more appropriate credits for NEM generation, the net cost of service for NEM customers drops significantly. With these revised credits, the gap between revenue collected and net cost of service declines relative to APS's analysis. It is important to note that my analysis of net cost of service is conservative in that it assumes all solar systems are oriented toward the south (thereby underestimating the avoided demand credits). In addition, my net cost of service does not include any credit for certain important direct benefits provided by NEM customers (e.g., fuel hedging or market price mitigation) or any societal benefits (e.g., reduction in emissions and water use, improvements to the local economy) identified by TASC witness Mr. Beach in his opening testimony.

The Commission should defer consideration of APS's proposals to establish a new customer class for NEM customers as well as decisions about the reasonableness of APS's COSS until the next APS general rate case.

II. This Proceeding Is Not The Appropriate Place To Consider Cost Of Service Issues; This Topic Is Best Examined In General Rate Cases

Q. Why has TASC chosen to submit testimony related to APS's COSS in this docket?

A. APS submitted a COSS in this docket as requested by the Commission.[2] As a result, TASC felt that it was necessary to point out to the Commission the significant flaws in APS's COSS.

Q. Does TASC believe that this docket is the appropriate venue to examine cost-of-service issues or establishment of new rate classes?

A. No. APS is proposing a dramatic restructuring of rates through a detailed cost model that, in the current proceeding, can only be addressed on a highly expedited schedule. As a fundamental policy consideration, the rate proposal and underlying analysis deserves full examination in its own proceeding. The appropriate place to consider the inputs and structure of APS's COSS is in the APS general rate case, where cost-of-service issues are carefully vetted by all parties. Also, in a general rate case, the question of whether to establish new rate classes could be examined by all interested parties. That is not the case in this proceeding.

Q. Does APS's COSS submitted in this docket incorporate value of solar methodologies under development or other findings established in this proceeding?

A. No. APS explicitly refuses to incorporate in its COSS value that is unique to solar DG, such as transmission and distribution cost savings, or environmental and economic benefits; APS values solar only based on avoided generation demand and energy costs.[3]

Q. Are there other reasons to defer consideration of COSS issues until the next general rate case?

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[2] Docket No. E-00000J-14-0023, Procedural Order, December 3, 2015, p. 1 (setting testimony schedule regarding value and cost of DG as well as APS's cost of service for DG and non-DG customers).

[3] Direct Testimony of Leland R. Snook on behalf of Arizona Public Service Company (APS), Docket No. E-0000J-14-0023, February 25, 2016 (Snook Testimony), pp. 15-17.

A. Yes. There are obvious shortcomings in the basic COSS assumptions, which are detailed later in my testimony. The current schedule does not allow adequate time to propound discovery and to fully develop more proper inputs for the COSS. Even more importantly, APS was unable to provide intervenors with a fully functional COSS model in response to discovery. As a result, intervenors did not have an opportunity to perform alternative modeling runs to test the sensitivity and reasonableness of the APS COSS model.

Q. What actions do you recommend that the Commission take with regards to consideration of APS's COSS in this docket?

A. The Commission should note the flaws in the reasonableness of the APS COSS in this proceeding but delay making any final determinations regarding the COSS until APS's next general rate case. In addition, the Commission should also give no weight to APS's flawed COSS in the determination of the value of solar being determined in this docket. Instead, the Commission should rely on the value of solar analysis presented in this docket by TASC witness Mr. Beach.[4]

III. A COSS Does Not Accurately Assess The Validity of Resource Planning Decisions

Q. What does APS claim is the value of its COSS in this docket?

A. APS states that if NEM customers were hypothetically viewed as a separate customer class or sub-class, then NEM customers would only pay a small fraction of their cost of service as based on APS's COSS.[5]

Q. Is this a reasonable perspective?

A. No, it is not for two reasons. First, as discussed in the next sections, it is not reasonable to treat NEM customers as a separate rate class. APS provides no compelling data to show

[4] Direct Testimony of B. Thomas Beach on behalf of The Alliance for Solar Choice (TASC), Docket No. E-0000J-14-0023, February 25, 2016 (Beach Testimony).
[5] Snook Testimony, pp. 3-4.

that the usage characteristics of NEM customers are sufficiently different from a typical customer in the same class to warrant such a change. Second, looking exclusively at the COSS, is not a reasonable method to evaluate the value of solar. Customers make long-term investments when they decide to install solar on their homes. These long-term investments provide long-term benefits to APS, allowing it to avoid generation, transmission, and distribution costs for all customers (not just a subset of solar customers) over the lifetime of the solar panels. In addition to reducing the demands on APS's generation, transmission, and distribution systems for existing customers, NEM customers also export power to the APS distribution system. These exports from NEM customers to the distribution grid provide APS with additional long-term power supplies dispersed throughout APS's service territory.

Q. Does APS's COSS account for these long-run benefits of NEM?

A. No. Those long-run benefits are ignored in APS's COSS since the COSS focuses only on a single historic test year. APS notes that "[i]n a COSS, the tangible benefits in the study period of rooftop solar are included" and that a value of solar analysis "does not look at actual costs, and is fundamentally different than a COSS. It involves predicting the marginal benefits of solar over the next 20 or 25 years, and often includes both operation and societal benefits."[6]

Q. Would APS's COSS be a reasonable tool to use to evaluate the reasonableness of other long-run resource investments?

A. No. A single-year snapshot of the costs and benefits of a long-run resource is clearly unreasonable. It is highly unlikely that APS would use such an approach to evaluate the cost-effectiveness of other long-run resource options.

[6] Snook Testimony, p. 29.

Q. Can you provide an example?

A. Yes. Assume that APS is considering developing a new APS-owned generating facility. The fixed costs of that new generating facility are not equal over time. Rather, the fixed costs are front-loaded and decline over the life of the project. It would be unreasonable to examine the reasonableness of such a long-term investment using a one-year snapshot, especially since the costs and benefits of the generation facility would change significantly over time. Similarly, the long-run benefits and costs of NEM will evolve over time, making a snapshot view of the impacts of NEM almost meaningless.

Q. What do you conclude from this?

A. The COSS submitted by APS in this docket provides little information about the long-run value of NEM resources and the Commission should give it no weight in assessing the value to all customers of long-term solar investments by NEM customers.

IV. APS Does Not Provide Compelling Evidence Justifying the Need For A New Class For NEM Customers

Q. Does APS recommend that NEM customers be assigned to a separate class?

A. Yes. APS proposes to establish a separate customer class for residential NEM customers that is distinct from the existing residential customer class, claiming that NEM customers have very different costs of service and load characteristics.[7]

Q. How do you respond to APS's claim that NEM customers have very different costs of service?

A. As discussed in the next section of this testimony, APS's COSS is fraught with methodological problems and improper assumptions. These problems include:

[7] Snook Testimony, pp. 11,12.

- assuming that generation from NEM customers do not avoid any transmission or distribution demand costs;
- allocating demand costs for distribution substation and primary distribution using the incorrect allocator; and
- ignoring the generation demand reductions associated with NEM deliveries to the distribution grid.

Because of these modeling problems, the Commission should give no weight to recommendations from APS regarding the need for a new customer class based on its COSS.

Q. How do you respond to APS's claims that NEM customers have very different load patterns and, as a result, should be placed in a separate rate class?

A. There is no question that NEM customers do not have delivered load shapes that mimic those of the "average" residential customer. However, the same could be said for many other sets of customers that are currently in the residential customer class. There are significant variations in load shapes, both among customers with similar end uses in their residences, and between customers that have installed various load-modifying technologies in their homes. Despite this, APS does not appear to be moving to create separate customer sub-classes for these other groups of customers, only NEM customers.

Q. Has APS demonstrated that the loads characteristics of NEM customers are outside the range of load variation that is seen within the residential class?

A. No. APS uses selected examples of customer classes to try to demonstrate this. However, APS only focuses on the average of all of those customers, not on the range of loads shown by those customers. As a result, APS's analysis does not provide compelling evidence that NEM customers are well outside of normal variation in loads seen in the residential class.

Q. How do you respond to APS's claims that residential customers on energy efficiency programs have "a load shape that is very similar to the average APS residential customer."[8]

A. APS witness Mr. Snook's "load shape" for customers that participate in APS's energy efficiency program consists of a single summer and a single winter day for "residential customers participating in the following measures: CFLs, duct test and repair (AC) and conservation behavior."[9] This is a very limited subset of possible energy efficiency measures. For example, APS witness Mr. Snook ignores customers that install smart thermostats to control air conditioner loads. Such a technology would clearly have a different load shape on a summer day than would a typical customer without a smart thermostat, likely resulting in much lower usage during daytime hours, and somewhat greater usage in the evening hours.[10] In fact, APS even has a demand response program that takes advantage of smart thermostats.[11]

Q. Can you demonstrate the changes in load shape that other behind-the-meter technologies cause to customer's load shapes?

A. I had hoped to provide the Commission with information about how different behind-the-meter technologies result in significant changes to the "typical" load shape for APS's residential customers. Unfortunately, APS refused to provide hourly load data to allow for this analysis.[12] However, there is little doubt that those different subsets of customers would have hourly load shapes that differ from the "typical" residential customer.

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[8] Snook Testimony, p. 24.

[9] Snook Testimony, Figures 4 and 5, pp. 26-27.

[10] There might also be significant differences in usage patterns among customers with similar end-use controls. Consider a house with a setback thermostat. If the thermostat's batteries fail, then the thermostat will likely not set the customer's thermostat to a higher setpoint during the day, meaning that the customer would have a higher electric demand than otherwise expected based on the delivered load of a typical customer with a setback thermostat.

[11] APS offers business customers the "Peak Solutions" program, which controls smart thermostats. https://www.aps.com/en/business/savemoney/solutionsbyequipmenttype/Pages/thermostats-and-energy-controls.aspx

[12] See APS's Supplemental Response to TASC Data Request 4.1 (See Exhibit WAM-2). It is surprising that APS was unable to provide hourly load data for the subset of customers that are participants in APS's energy efficiency or demand response programs since APS seems capable of developing average hourly loads for at least two months for a subset of customers that have installed certain energy efficiency measures (see Snook Testimony, Figures 4 and 5, pp. 26-27). In addition, APS claimed that it was unable to provide hourly load data for apartment customers,

Q. Were you able to find studies with actual residential load data illustrating the impact energy efficiency programs (including smart thermostats) have on load profiles?

A. I was not able to find studies which included actual residential load data, but there are several studies which simulated various residential energy scenarios. The National Renewable Energy Laboratory's (NREL) Integrated Energy System Model (IESM) analyzes the impact so-called Home Energy Management Systems (HEMS). These are systems which, among other things, control household temperature. Depending on the setup, these HEMS can be quite complicated, communicating in real time with the grid to determine the optimal time to operate the household appliances. NREL's IESM is "designed to perform simulations of a distribution feeder, end-use technologies deployed on it, and a retail market or tariff structure."[13]

A June 2015 study simulated 20 HEMS-equipped houses on a single distribution feeder in the state of North Carolina during the month of July. The feeder is populated with 20 well-insulated houses, all connected through four 25 kVA single-phase, center-tapped transformers.[14] The desired temperature is dictated by the EPA's Energy Star recommendations.[15] The figure below shows the impact of three different HEMS penetrations (0%, 50% and 100%):

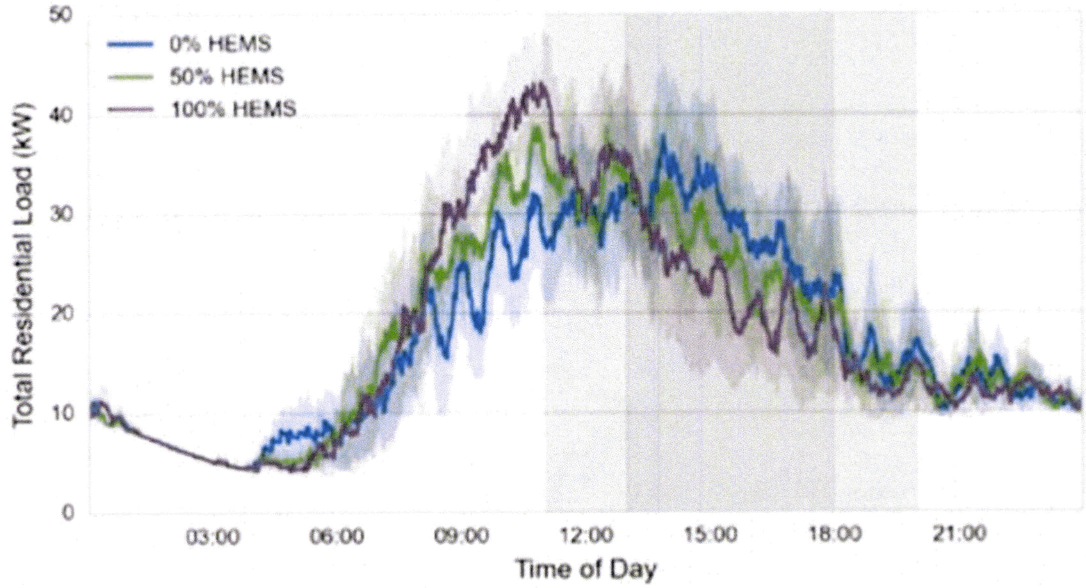
customers that use dual fuels, or seasonal customers. This is also surprising since Figures 4 and 5 of Mr. Snook's testimony appears to present average hourly loads for January and July for those customers.

[13] Ruth, Mark, Annabelle Pratt, Monte Lunacek, Saurabh Mittal, Hongyu Wu, and Wesley Jones. "Effects of Home Energy Management Systems on Distribution Utilities and Feeders Under Various Market Structures," National Renewable Energy Laboratory, presented in the *23rd International Conference on Electricity Distribution*, Lyon, France, June 15-18, 2015 (NREL 2015), p. 2 (See Exhibit WAM-4). Also available at http://www.nrel.gov/docs/fy15osti/63500.pdf

[14] NREL 2015, p. 2 (See Exhibit WAM-4).

[15] Energy Star: Program Requirements for Programmable Thermostats," p. 7 (See Exhibit WAM-5). Accessed April 5, 2016. Also available at: https://www.energystar.gov/ia/partners/prod_development/revisions/downloads/thermostats/ProgramThermDraftI.pdf?0b55-1475.

Figure 1: Load Profiles of Various Levels of Home Energy Management Systems Penetration



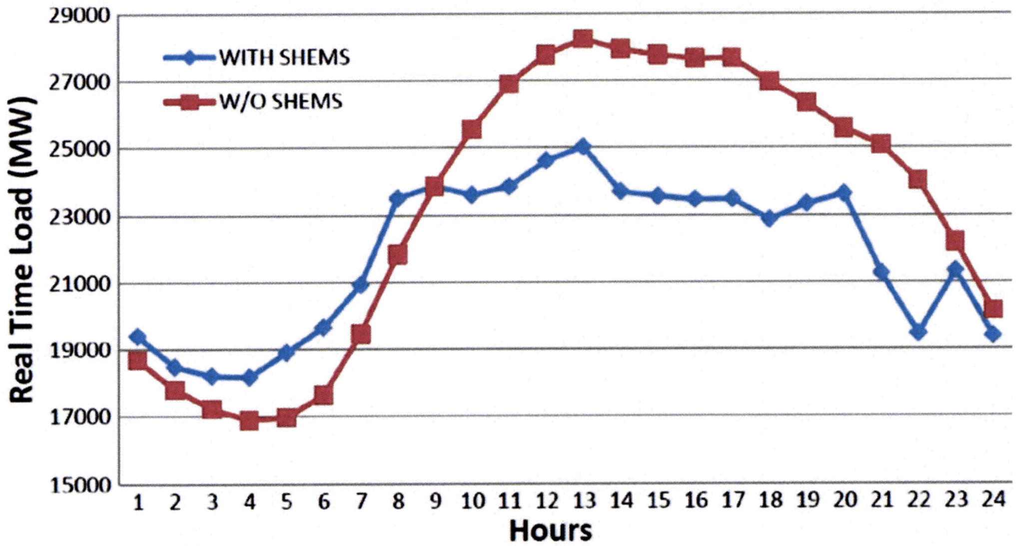
Source: NREL 2015 p. 4 (See Exhibit WAM-4).

Under a simulated time-of-use tariff, the presence of HEMS shifts customer load to earlier in the day, when electricity prices are less expensive.[16] The highest HEMS penetration results in the lowest load during the maximum pricing period (darkest grey shaded portion).

A December 2013 paper studied the impact of HEMS on a randomly selected day in the New York ISO region. Different than NREL's IESM, the HEMS in this study was designed to collect real time pricing data and customer preferences/activities to optimize the electricity load. Residential energy consumption (including washer/dryers, heating/air conditioning, water heating and electric vehicle charging) was simulated to investigate how HEMS shifts load curves. The results are shown in the figure below.

[16] NREL 2015 p. 3 (See Exhibit WAM-4).

Figure 2: Load Curves With and Without Home Energy Management Systems



Source: Qinran Hu, and Fangxing Li. "Hardware Design of Smart Home Energy Management System With Dynamic Price Response." *IEEE Transactions on Smart Grid* 4, no. 4 (December 2013): 1878–87. doi:10.1109/TSG.2013.2258181. (IEEE 2013), p. 1886 (p.9 of pdf) (See Exhibit WAM-6).

Not only do HEMS shift load to earlier in the day (the HEMS profile is higher between 1:00 and 6:00 am), but they "reduce the loads in peak hours by nearly 10 percent which is significant."[17]

Q. Has APS proposed to establish different rate classes for residential customers with these various behind-the-meter load modifying equipment?

A. I am not aware of APS making such a proposal. Such a proposal could prove to be administratively burdensome. I understand that Staff does not support the creation of a multitude of customer classes based on the end-use modifying technologies that a customers have,[18] stating that it "concludes it is best if utility rates are designed to be neutral, agnostic, and unbiased toward the technology and lifestyle choices of customers."[19]

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[17] IEEE 2013, p. 1885 (p.8 of pdf) (See Exhibit WAM-6).
[18] Direct Testimony of Thomas M. Broderick, Docket No. E-04204A-15-0142, December 9, 2015 (Broderick Testimony), pp. 6-7; Direct Testimony of Eric Van Epps, Docket No. E-01575A-15-0312, March 18, 2016, pp. 2, 10.
[19] Broderick Testimony, pp. 6-7.

Q. What do you conclude regarding APS's claim that NEM customers should be in a separate customer class because of their different load shapes?

A. APS is being selective in its application of what it means by "different load shapes." When residential customers employ various behind-the-meter technologies, they have load shapes that are "different" than the average load shape in the same way that NEM customers have delivered loads that are "different." Because of this and because APS's COSS is unreliable, I do not believe that APS has met its burden of proof regarding the need to establish a new customer class for NEM customers and, as a result, the Commission should reject APS's proposal.

V. APS'S COSS Is Flawed And Should Be Given No Weight

Q. What is the purpose of this section?

A. This section summarizes APS's COSS assumptions and modeling approach and identifies significant flaws with the COSS.

A. APS's COSS Model and Assumptions

Q. What are APS's key proposals in this proceeding regarding cost of service issues?

A. As discussed above, APS proposes to establish a separate customer class for residential NEM customers that is distinct from the existing residential customer class, claiming that NEM customers have very different costs of service and load characteristics.[20] Because of these claimed differences, APS recommends that NEM customers be assigned to a separate customer class than other customers.

In addition to assigning NEM customers to a different customer class than other residential customers, APS also supports use of a three-part tariff for NEM customers.[21] This tariff would have a large basic service fee, a large non-coincident demand charge, and a relatively small energy charge.

[20] Snook Testimony, pp. 11,12.
[21] Snook Testimony, p. 27.

To support its proposal, APS provides, among other things, a COSS. In this COSS, APS proposes to use the gross electricity usage by NEM customers[22] instead of the actual electricity delivered by APS as a key billing determinant.[23]

Q. Does APS deliver energy to a NEM customer to meet the customer's gross electric load?

A. Not at all times of the day. TASC witness Mr. Beach's opening testimony in this docket summarizes the three different delivery periods for NEM customers.[24] As shown in Mr. Beach's testimony, when the NEM customer's solar system is not generating, APS delivers energy to meet the customer's entire electric load. However, at other times of the day, APS deliveries only supply a fraction of the customer's electric load, with the rest of the load being met by the NEM customer's solar system. If the solar system is generating less than the customer's gross electric load, then the solar system acts exactly like energy efficiency, reducing the energy delivered at that time by APS. Finally, in other hours, the customer's solar system generates more electricity than the customer can use onsite at that time, resulting in deliveries of electricity to the APS distribution system. APS takes possession of the power delivered by the NEM customer to the APS distribution system at the NEM customer's meter and the power is used by APS to meet demands by other customers on the distribution feeder.

Q. How does APS account for energy that a NEM customer generates in its COSS?

A. APS claims that it models generation from NEM customers by crediting the customer for self-provided capacity and for energy that is both consumed onsite and exported to the APS grid.[25] APS values this energy at its posted tariff for excess sales from NEM customers, Schedule EPR-6[26], which APS witness Mr. Snook characterizes as avoided

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[22] APS calls this the "site load."
[23] Snook Testimony, p. 15.
[24] Beach Testimony, p. 11.
[25] Snook Testimony, p. 15.
[26] APS Response to Vote Solar Data Request 2.3, p. 1 of 2 (See Exhibit WAM-3), which refers to APS15773.

fuel costs.[27] It then reduces the cost of service for the solar customers based on this value.[28] APS also provides a 19% production demand credit.[29]

Q. Does APS claim that its proposed approach to developing allocators for residential NEM customer generation fully credits NEM customers for the benefits that they provide to the grid?

A. Yes. APS states that "[t]his approach fully credits residential solar customers for all cost savings resulting from the capacity and energy supplied to the grid by their rooftop solar systems."[30]

Q. Does the credit APS assigned to residential rooftop solar generation in its COSS include the value of benefits that these resources provide to its transmission and distribution system?

A. No. APS states that its COSS methodology "did not include savings for transmission or distribution costs, nor did it include environmental or economic development benefits."[31]

Q. Why does APS believe that ignoring these two benefits in its credit calculation results in a credit that is fully compensating NEM customers?

A. APS argues that "the 2014 data make clear that customers with rooftop solar which was installed without regard to location did not cause any transmission and distribution savings."[32]

Q. Please describe the assumptions used by APS to develop the credits for energy produced by the NEM customers.

A. APS's credit is equal to the energy generated by the NEM customers (270,312 MWh at the customer level) multiplied by the non-time-differentiated price for non-firm power under Schedule EPR-6 ($0.02895 per kWh).[33]

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[27] Snook Testimony, p. 17.
[28] Snook Testimony, pp. 15-16.
[29] Snook Testimony, p. 16.
[30] Snook Testimony, pp. 15-16.
[31] Snook Testimony, p. 17.
[32] Snook Testimony, p. 18.

Q. Does this approach under-value the energy produced by NEM customers?

A. Yes. Using a non-time-differentiated price for the energy credit under-values the energy produced by the NEM customer since solar generation occurs during daylight hours, which is when the value of energy is higher than at night.

Q. How are you sure that the energy credit is based on the total generation by the NEM customer's system?

A. APS provided a workpaper that presented the total generation by NEM customers. The values from that workpaper matched the total solar generation amount shown in APS's workpaper supporting the calculation of the energy credit, which was provided in response to Vote Solar Data Request 2.3.[34]

Q. Please describe the assumptions used by APS to develop the credits for generation demand.

A. APS uses a different approach to calculate the generation demand credit than it uses to calculate the energy credit. APS calculates the generation demand credit by averaging the percentage change in (1) the change in Coincident Peak Demand averaged over the months of June-September between Solar Site and Delivered loads and (2) the change in Class Non-Coincident Peak (On-Peak) averaged over the months of June-September between Solar Site and Delivered Coincident Peak Demand averaged over the months of June-September for Solar Site and Delivered and Delivered loads. **Table 1** presents this calculation for NEM customers taking service under APS's Energy Rate option.

Table 1: APS's Derivation of Generation Demand Credit

Month	Coincident Peak (MW)		Class NCP (On-Peak) (MW)	
	Delivered	Site	Delivered	Site
June	76.5	104.1	93.4	104.8
July	94.9	122.5	111.3	122.5

[33] APS Response to Vote Solar Data Request 2.3, Attachment APS15768, p. 1 of 37 (See Exhibit WAM-3).

[34] See Response to Vote Solar Data Request 1.1, file "Allocation Factors (TYE 12312014), APS15746.xlsx", tab "Input," cells D173 and D177, a copy of which is presented in Exhibit WAM-3. Note that these cells are labeled in part "Total Solar Generation" or "Solar Generation."

August	93.2	119.8	94.2	105.1
September	60.0	103.8	99.2	107.1
Average	81.2	112.6	99.5	109.9
Relationship – Delivery versus Site		27.90%		9.42%
Peak 2 Point Average				**18.66%**

Source: APS Response to Vote Solar Data Request 2.3, Attachment APS15768, p. 2 of 37 (Exhibit WAM-3)

Q. Does this calculation provide a generation demand credit for generation that NEM customers deliver to the distribution system?

A. No. This calculation only provides a generation demand credit based on the difference between the Solar Site Electricity and the Delivered Electricity. APS provided definitions of these terms:

- Solar Site Electricity is equal to [Delivered Electricity + (Produced Electricity – Received Electricity)];
- Delivered Electricity is measured energy delivered from APS to customers; and
- Received Electricity is energy delivered from the customer to APS.[35]

From this, it is clear that Solar Site Electricity less Delivered Electricity is equal to Produced Electricity – Received Electricity, meaning that APS's generation demand credit is not based on total Produced Electricity but on energy used directly by the NEM customer. This means that APS's does not provide a generation demand credit for Received Electricity.

Q. Is this the only flaw in APS's COSS modeling?

A. No. The following sections discuss the overall flaws in the APS COSS modeling and certain specific errors in the assumptions used in the COSS.

[35] See APS Response to Vote Solar Data Request 2.4, provided in Exhibit WAM-3.

B. APS's Overall COSS Modeling Approach Has Serious Flaws

Q. Did APS use a reasonable approach for determining the net costs to serve NEM customers in its COSS?

A. There are two ways that APS could have properly determined the net costs to serve NEM customers. One way would be to develop cost allocators for NEM customers in the COSS based on the load and peak demands associated with electricity delivered by APS and then to develop a credit associated with excess energy delivered by NEM customers to the APS distribution grid. The other way would be to calculate NEM customers' cost of service based on their gross load and then to develop credits for avoided generation, transmission, and distribution demand costs and avoided energy costs based on the entire output from the NEM customers' solar systems. Instead, APS used a flawed hybrid approach: it used the gross electric usage of NEM customers (i.e., delivered load plus solar generation used behind the meter by the NEM customer) in its COSS but then failed to provide the appropriate credits for NEM customers' solar generation by (1) failing to account for excess energy delivered by the NEM customers to the distribution grid and (2) simply ignoring the costs that NEM customers avoid on the transmission and distribution systems.

Q. Please explain.

A. APS is not fully accounting for the benefits NEM customers provide in developing its COSS. It is explicitly omitting several of the value categories that NEM customers provide and which are actively being contemplated in this proceeding. As discussed elsewhere, using the proper allocators for distribution substations and primary wires reduces the distribution demand costs that should be allocated to residential NEM customers. Also, APS does not provide any credit for avoided generation demand associated with generation that NEM customers deliver to the distribution system. Given that the very purpose of this proceeding is to establish the value of solar and methodologies for quantifying it, it seems premature to file a cost study that has already determined the value of solar to be zero.

Q. Does evidence from other utilities demonstrate that distributed generation can potentially reduce transmission and distribution infrastructure costs?

A. Yes, Pacific Gas & Electric recently stated that a flattening of its load forecast due to energy efficiency and rooftop solar has eliminated the need for $200 million of sub-transmission projects, which were recently eliminated in the California Independent System Operator's 2015-2016 Transmission Plan.[36]

Q. What other factors should be taken into account in considering the impact of solar PV generation on distribution costs?

A. A variety of factors influence the overall impact of solar PV on system and distribution feeder capacity. It is worth noting that distributed solar PV is typically not a single resource, but many small resources. For this reason, although the average output of any given system is intermittent, it is very unlikely that a significant portion of the overall resource fleet has a forced outage (i.e., is unavailable due to maintenance or technical problems) at any given time. Thus, availability of the resource is likely quite high. Additionally, geographic diversity, even over a relatively small area, could in some cases make the overall solar PV resource much more reliable than a single system on even a partly cloudy day by averaging the intermittency across the entire area.

Q. How could these nuances of distributed generation resources be better taken into account in order to provide APS with benefits such as avoided transmission and distribution investments?

A. By considering distributed generation more carefully in the transmission and distribution planning process, cost savings could be realized more readily. For example, not only could a detailed review of fleet-wide resource reliability yield greater insight into potential opportunities to avoid certain distribution investments, but this type of analysis could facilitate an ongoing two-way process. Once it has a comprehensive view of how distributed generation impacts the system and might create savings, APS could engage in more proactive resource planning where it incentivizes customers to install, for example, solar PV in locations and with orientations that create the most benefit. Such an approach

[36] California Energy Markets. *Cal-ISO Board Approves Annual Transmission Plan*. Issue No. 1379, p. 10. April 1, 2016 (See Exhibit WAM-7).

could maximize factors like geographic diversity and timing of peak solar output. Rather than being unexpected, distributed generation would be a part of APS's overall plan.

Q. What does APS's assumption regarding valuing generation from a NEM customer's solar system at avoided costs assume about the ability of NEM customers to avoid usage of APS's transmission and distribution system to serve NEM customers?

A. APS's narrow view of avoided costs only considers avoided costs for generation demand and energy.[37] As a result, the credits that APS uses in its COSS to account for the value of solar supplied by NEM customers explicitly assumes away any potential benefits of the solar generation on costs for providing transmission or distribution service. This is clearly unreasonable.

Q. Why is this unreasonable?

A. By assuming that all NEM customers' solar systems do not reduce demands on the APS distribution system, APS effectively assumes that all solar systems owned by NEM customers on each distribution feeder fail to generate at precisely the same moment, essentially requiring standby service. This is not a reasonable assumption given the geographic diversity and high reliability of photovoltaic systems during daylight hours.

Q. Is it reasonable to ignore the impact of the energy that NEM customers inject onto the system when their generation exceeds their load?

A. No. This power is consumed by other customers on the distribution system; it is not fed back onto the transmission system through the interconnection between the transmission and distribution systems.[38] As such, it reduces the loads that APS must serve on the feeder upon which the NEM customer is located or on another part of the distribution system. Thus, it effectively reduces the cost to serve other residential customers on the distribution system by reducing loading on the interconnection between the transmission and distribution systems as well as the distribution substations and primary wires. It also reduces loading on the transmission system for those customers. Finally, it reduces the amount of generation that APS must supply to those customers. For that reason, it would

[37] Snook Testimony, pp. 15-17.
[38] See APS Response to TASC Data Request 4.4 (See Exhibit WAM-2).

be reasonable to ignore the impact of excess NEM generation in determining the net cost of service for NEM customers.

Q. What would be the effect of changing this assumption?

A. By properly crediting the value of excess generation from NEM customers to the solar customer class, the cost of service for those customers will be reduced relative to the cost of service estimated by APS.

Q. Have you developed an estimate for this benefit?

A. Yes. My estimated credits discussed below account for both solar energy that is used by NEM customers onsite as well as energy that NEM customers inject onto the distribution system.

Q. What do you recommend?

A. APS's COSS cannot be used to develop the appropriate cost of service based on delivered loads. Therefore, I was unable to develop estimates of the actual cost to serve NEM customers based on delivered load plus a credit for deliveries of excess generation to the APS distribution grid. As a result, I develop alternate estimates of the various costs avoided by NEM customers. These credits are much larger than those developed by APS.

C. APS Relies on Flawed Assumptions in Its COSS

Q. What is the purpose of this section of your testimony?

A. This section identifies various flawed assumptions used by APS in its COSS. The use of these flawed assumptions renders the results of APS's COSS meaningless with respect to valuing NEM customers. The flawed assumptions described below are:

1. Allocating costs based on gross load instead of delivered load overstates allocation of distribution costs to the hypothetical NEM class; and
2. Allocating costs based on non-coincident peak overstates allocation of certain infrastructure (i.e., primary distribution and distribution substation) to NEM customers.

1. APS Unfairly Uses Different Billing Determinants To Allocate Costs To NEM Customers

Q. What are the specific allocators that APS uses to allocate generation and distribution demand costs to different customer classes?

A. APS uses the Average and Excess allocator to allocate generation demand costs to customers. APS uses Non-Coincident Peak Loads for customers to allocate demand costs for distribution substations and primary distribution lines. APS uses the Sum of Individual Max demands to allocate demand costs of distribution transformers and secondary distribution lines.[39]

Q. How does APS develop these allocators for its non-NEM customers?

A. APS uses metered loads to develop allocators for its COSS.[40] This is the approach that APS has historically used to allocate demand costs to residential (and other) customers.

Q. Does APS propose to use metered loads to develop the allocators for residential NEM customers?

A. APS uses the NEM customer's gross load at the home (i.e., load served both by APS and the customer's rooftop solar system) as the starting point for cost allocations to develop the Coincident Peak (CP), the Non-coincident Peak (NCP) and the Sum of Individual Max demand allocators.[41]

Q. Is APS's proposed approach to developing allocators for residential NEM customers based on a historical approved methodology specific to NEM customers?

A. No. APS is proposing a new sub-class of residential customers and is therefore proposing a new methodology for residential NEM customers.[42]

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39 Snook Testimony, p. 11.
40 Snook Testimony, p. 11.
41 Snook Testimony, p. 15.
42 Snook Testimony, pp. 11-12.

Q. Why does APS use different methodologies for incorporating loads for NEM and non-NEM customers into its COSS?

A. APS appears to believe that it must account for load that would have materialized had the customer not installed solar DG, and then credit the customer for DG after the fact. APS does not justify why it chose this relatively complicated approach rather than simply using metered load.

Q. Is this approach reasonable?

A. It is one way to attempt to measure the net costs that NEM customers impose on the APS system. However, as discussed below, APS chooses to ignore at least one component of avoided costs in its application of this approach. For this reason, APS's estimates overstate the costs to serve NEM customers.

Q. Does APS use a similar approach for allocation of costs to other residential customers that modify their delivered loads by installing technology behind-the-meter?

A. No. Despite the fact that customers can and do install energy efficiency measures, participate in demand response programs, or install appliances that do not use electricity to serve end-uses that other APS customers serve using electricity and that these measures result in changes in their demands on the distribution system, APS uses the metered load as the basis for allocating distribution costs for those customers. In other words, APS reduces cost allocation to non-NEM customers for reducing demands on the distribution system through load modifications using behind-the-meter technology.

Q. What would be the impact if APS were to use the metered loads for NEM customers to derive the billing determinants used in the COSS instead of the derived loadshape that it is proposing to use?

A. Using metered loads for the residential solar customers would likely reduce the distribution demand costs that are allocated to those customers. This would reduce the difference in the COSS between revenues collected through rates and the revenue requirements for the residential NEM class as constructed by APS.

Q. Have you estimated the impact on the COSS of your proposed change in allocators?

A. I attempted to estimate the impacts of revising the cost allocators and billing determinants used in APS's COSS but was unable to do so because APS's "working" COSS model was not fully functional.[43] As a result, I develop estimates of credits that should be applied against the costs to serve NEM customers to arrive at the net cost of service for those customers.

2. Use Of NCP To Allocate Substation and Primary Distribution Costs Is Incorrect

Q. Is the use of NCP for NEM and non-NEM customers reasonable for allocation of distribution demand costs?

A. APS's own data shows that its loads on a representative sample of distribution feeders are highly correlated with system peak demands and are not randomly distributed. The following figure presents the loads on 8 representative feeders by month (colored lines). Also shown in these figures is APS's system peak load (black dashed line).[44]

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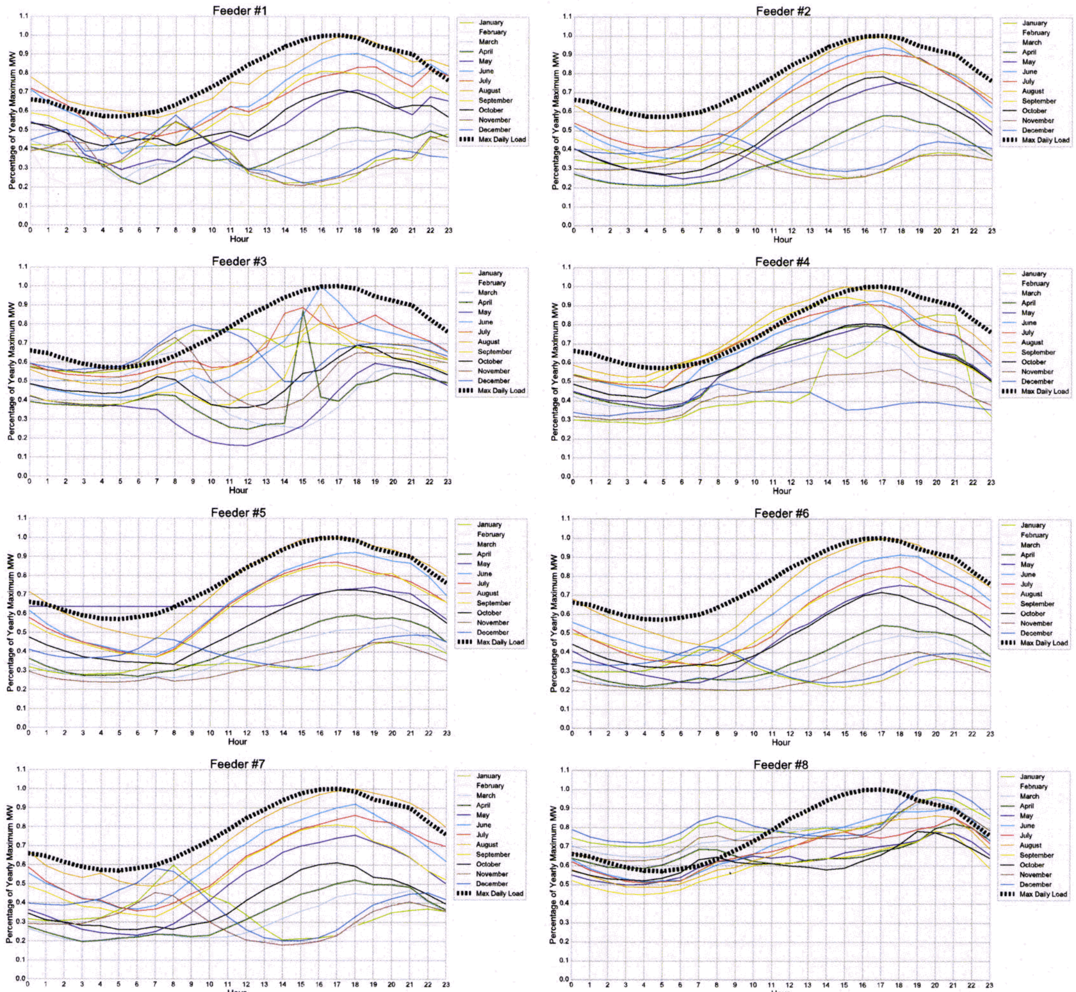
[43] APS's "working" model was not linked to the model that APS claims was used to develop the billing determinants and allocation factors that are used in the COSS. The data structure for inputs to the "working" model was very different than the data structure for the outputs from the "allocation factor" model. As such, it was not possible to use the "working" model to examine the impact of different allocation factors or billing determinants on the cost of service for NEM customers.

[44] These figures present the hourly load on each feeder on the day with the maximum demand for each month, normalized using the maximum feeder loading for the year. Data based on APS Response to TASC Data Request 1.15, which is presented in Exhibit WAM-2.

Figure 3: Normalized Hourly Loading on Representative Feeders



Q. How were these figures[45] developed?

A. For each representative feeder, the maximum daily load for each month was normalized. I determined the maximum annual loading on each feeder and the day of each month with the monthly maximum loading of that feeder. I then normalized each hourly load for the 12 peak days by the annual maximum loading. Similarly, the maximum load (dashed

[45] See Exhibit WAM-8 for larger versions of these figures.

black line) is the hourly load of the day with the highest demand of the year divided by the maximum peak hour demand for the year.

Additionally, there were five anomalous days (**Table 2**) that were smoothed by averaging the hourly value of the previous day and the next day.

Table 2: Anomalous Days

Feeder	Month	Day	Hours Smoothed
3	April	14	14, 15
3	April	15	11
3	April	16	11, 12, 13, 14
8	May	18	11
8	May	19	11

Q. Please discuss your conclusions from these figures.

A. As seen from these figures, it is clear that during the summer months, which is when APS's system demands peak, there is a high coincidence between APS's loads and the loads on these representative feeders. Maximum monthly demand for Feeders 1, 2, 4, 5, 6 and 7 occurs in August between 3:00 and 6:00 pm. The maximum daily load (also occurring in August) peaks at 5:00 pm. Thus, use of NCP is not the appropriate allocator to use for allocating APS's distribution demand charges and the appropriate allocator is the coincident peak demand.

Q. What portion of the APS distribution system is loaded consistent with the figures shown above?

A. The loading on the feeders shown in the figures is the load that is delivered from the APS transmission system to the feeders through the distribution substations and over the primary distribution lines. From these figures it is clear that the loading of the distribution substations and primary distribution lines is coincident with peak demand.

Q. What is the more appropriate allocator to use for distribution demand costs related to distribution substations and primary distribution lines?

A. For these components of the distribution system, it would be more appropriate to use a cost allocator for generation and transmission demand costs instead of NCP.

Q. What would be the impact if APS were to allocate primary wires and distribution substation costs based on the same allocator as used for generation demand?

A. If the actual metered loads for solar customers were used in the allocation process, there would be a reduction in substation and primary wire-related distribution costs allocated to residential solar customers. This would reduce the difference in the COSS between revenues collected through rates and the revenue requirements for the residential solar class as constructed by APS.

Q. Have you estimated the impact of your recommended allocator on the COSS?

A. No. As noted above, APS's "working" COSS model could not be used to apply different sets of billing determinants or allocators to determine the cost of service for NEM customers. As a result, I developed a credit for avoided distribution costs as discussed below.

D. Revised Credits and Estimates Of Net Cost Of Service for NEM Customers

Q. What is the purpose of this section?

A. This section presents estimates of credits that should be netted against APS's cost of service estimates based on gross loads for NEM customers to arrive at the proper level of net cost of service for these customers. These credits differ from and are greater than the credits used by APS.

Q. Do you present credits for environmental impacts or other externalities?

A. While such credits are appropriately considered in a value of solar study (as discussed in Mr. Beach's testimony), I do not include those estimates here.

Q. How did you develop your recommended credits?

A. I used the Peak Capacity Allocation Factors (PCAFs) to determine the portion of primary distribution and distribution substation costs that are avoided by NEM customers.[46]

Q. Have others used a similar approach to determine cost responsibility or avoided costs for generation, transmission, and distribution demand costs?

A. Yes. As described by TASC witness Mr. Beach, the California Public Utilities Commission's Public Model, which was used to determine the cost-effectiveness of NEM resources, used PCAFs.[47] In addition, Pacific Gas & Electric (PG&E) allocates different parts of the costs of its distribution system using two different allocators. PG&E allocates primary distribution costs via PCAFs (which are similar to coincident demand) and allocates secondary distribution costs and new business on primary distribution costs based on FLTs (final line transformer loads, which are similar to non-coincident demand). PG&E does this by division (i.e., there's a separate marginal cost for each of these items for each division; each rate schedule gets a weighted average cost based on the amount of PCAF/FLT load in each division in that rate schedule.) PG&E describes this process as follows:

> The substation-level PCAF-weighted loads are weather-normalized weighted loads that indicate what contribution a class has made to a substation's peak. These PCAF-weighted loads are then summarized by division for the calculation of primary demand-related marginal cost revenue.
>
> FLT loads are either the class' diversified non-coincident demand at the FLT (residential and small commercial classes) or the class' undiversified non-coincident demand at the FLT (all other classes). Non-coincident demand is the class' highest observed demand during the year. As more than one residential or small commercial customer are served by a FLT, the FLT loads for these classes are scaled down (diversified) to reflect the fact that not all the customers served by that transformer will be operating at the time the FLT reaches its peak. For all the other classes, PG&E assumes that there is one customer per FLT.[48]

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[46] For this analysis, I did not include any other direct benefits of solar, such as fuel hedging or market price mitigation. See Beach Testimony, Exhibit 2, pp. 9-11.
[47] Beach Testimony, Exhibit 2, pp. 1, 12
[48] "Pacific Gas and Electric Company, 2014 General Rate Case Phase II, Prepared Testimony, Exhibit (PG&E-1), Volume 1: Revenue Allocation and Rate Design," Application 13-04-012, p. 2-8. (See Exhibit WAM-9).

This approach has been approved by the California Public Utilities Commission.[49]

Q. Has TASC developed PCAFs for allocation of demand costs in this proceeding?

A. Yes. TASC witness Mr. Beach developed PCAFs in support of his estimates of the value of solar in this docket.[50] Mr. Beach used the PCAFs to estimate the generation, transmission, and distribution demand costs avoided by NEM customers. Those same PCAFs are applicable here. These are presented below in **Table 3.**

Table 3: TASC-Recommended Demand Credits vs. Credits Proposed by APS

	Generation Demand	**Transmission Demand**	**Distribution Demand (Substation/ Primary Distribution)**	**Distribution Demand (Secondary/ Transformer)**
APS (Energy Rates)[51]	18.66%	N/A	N/A	N/A
APS (Demand Rates)[52]	14.64%	N/A	N/A	N/A
TASC (South-Facing)[53]	36.2%	36.2%	36.2%	20.1%
TASC (West Facing)[54]	53.21%	53.21%	53.21%	36%

Q. Has TASC developed revised energy credit rates?

A. Yes. TASC witness Mr. Beach has estimated that APS's avoided energy costs for solar DG as 4.215 cents per kWh for 2016.[55] I have used this value to assign energy credits to residential solar customers, as opposed to APS's 2.895 cents per kWh.[56]

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[49] The California Public Utilities Commission ultimately approved a settlement agreement using PCAF-based marginal distribution cost allocation factors: California Public Utilities Commission, D.15-08-005, *Decision Adopting Eight Settlements and Resolving Contest Issues Related to Pacific Gas and Electric Company's Electric Marginal Costs, Revenue Allocation, and Rate Design*. August 18, 2015 (See Exhibit WAM-10). *See also*: California Public Utilities Commission, A.13-04-012, *Settlement Agreement on Marginal Cost and Revenue Allocation in Phase II of Pacific Gas and Electric Company's 2014 General Rate Case*, Appendix A, July 16, 2014. (See Exhibit WAM-11).

[50] Beach Testimony, Exhibit 2, pp. 11-15.

[51] APS Response to Vote Solar Data Request 2.3, Attachment APS15768, p.2 of 37 (Exhibit WAM-3).

[52] APS Response to Vote Solar Data Request 2.3, Attachment APS15768, p.2 of 37 (Exhibit WAM-3).

[53] Beach Testimony, Exhibit 2, p. 12.

[54] Beach Testimony, Exhibit 2, p. 12.

[55] Beach Workpaper "Avoided Energy and Social Costs.xlsx," tab "Energy & Societal" Cell Q9

[56] APS Response to Vote Solar Data Request 2.3, Attachment APS15768, p.1 of 37 (Exhibit WAM-3).

Q. What would be the impact if APS were to allocate demand credits based on the PCAFs, and energy credits based on the rates developed by Mr. Beach?

A. Because each recommended credit is larger than the credit used by APS in calculating its net cost of service for NEM customers, the result of using the recommended credits would be to reduce the net cost of service relative to APS's estimates.

Q. Why is that?

A. APS only credits approximately 19% of the costs of generation demand to NEM customers. Mr. Beach's PCAFs credit NEM customers with between 36.2% and 53.2%, depending on the orientation of the PV system.[57] In addition, APS gives absolutely no credit to NEM customers for avoiding distribution or transmission demand costs. Regarding energy credits, APS uses a conservative value for avoided fuel costs, whereas Mr. Beach's energy credit rate more accurately reflects the actual avoided costs that APS would see.

Q. Is the application of larger credits the only factor that affects APS's stated contributions towards cost of service for NEM customers?

A. No. There is one further change that needs to be implemented to determine the net cost of service for NEM customers. Mr. Snook states in his testimony that the NEM customers on energy-based rates cover only approximately 36% of the cost to serve them while NEM customers on demand rates cover around 72% of the cost to serve them.[58] However, Mr. Snook also notes that past decisions in APS rate cases have established that the residential rate class covers a lower percentage of the cost of service as a whole (approximately 87%), and the difference is made up for by other customer classes.[59] Mr. Snook's calculations of NEM customers covering only 36% and 72% of the cost to serve them, for energy-rates and demand-rates respectively, are based on a retail ROR of 8.07% being applied across the board to all classes, thus implying the residential class has to cover the full cost to serve them, as opposed to a lower ROR as directed by the

[57] Beach Testimony, Exhibit 2, p. 12.
[58] Snook Testimony, p. 20.
[59] Snook Testimony, p. 20.

Commission. APS ignores its own target of a 4.99% ROR from these customers.[60] In effect, APS is ignoring the Commission's established policy regarding cost responsibility for the various classes in presenting its comparison of the percentage of costs of service recovered through rates. This is misleading at best.

Q. What adjustments would you recommend to the cost of service calculation, to implement the changes mentioned above?

A. I would recommend a two-pronged approach to estimating the true net cost of service for the hypothetical residential solar customer class:

1. In place of using an 8.07% ROR as Mr. Snook has done, an ROR of 4.99% should be used for developing the revenue requirement for NEM customers. This revenue requirement with a lower ROR should then be used for determining what percentage of the cost to serve NEM customers are already meeting. The return target of 4.99% is consistent with APS's method for calculating demand and energy credits for NEM customers.[61]
2. TASC's revised demand and energy credits should be used to determine the net cost to serve NEM customers.

Q. What would be the combined impact of these two changes?

A. The combined impact of these two changes would be to reduce the net cost to serve NEM customers.

Q. Have you estimated the appropriate credits that are associated with the solar generation by NEM customers?

A. Yes. I have calculated the estimated credits based on the credits discussed above. **Table 4** below presents a comparison between APS's energy credits, and TASC's revised energy credits.

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[60] APS Response to Vote Solar Data Request 2.1, Attachment APS15767, p. 2 of 48 (See Exhibit WAM-3).

[61] APS Response to Vote Solar Data Request 2.3, Attachment APS15768, p. 2 of 37 – 4 of 37 (See Exhibit WAM-3).

Table 4: Comparison between APS and TASC Energy Credits Allocated to Residential Solar Customers

	Generation (MWh)	Credit Rate ($/MWh)	Credit ($)
APS Solar Energy Credit	291,498	28.95	$8,438,867
TASC Solar Energy Credit	291,498	42.15	$12,286,641
Difference	0	13.2	$3,847,774

Table 5 below presents a comparison between APS's allocated demand credits, and TASC's recommended demand credits, using the credit percentages noted in **Table 3** for south oriented solar systems. The credits presented here are for solar customers on energy rates and demand rates combined, based on APS's targeted ROR of 4.99%.

Table 5: Comparison between APS and TASC Demand Credits Allocated to Residential Solar Customers

	Generation Demand	Transmission Demand	Distribution Demand (Substation/ Primary Distribution)	Distribution Demand (Secondary/ Transformer)	Total
APS' Solar Demand Credit	$2,356,788	$0	$0	$0	$2,356,788
TASC Demand Credit (South-Facing)[62]	$4,630,343	$1,034,833	$2,019,171	$688,104	$8,372,451
Difference	$2,273,555	$1,034,833	$2,019,171	$688,104	$6,015,664

Q. Have you estimated the impact of using the revised credits, and a 4.99% ROR on the net cost to serve NEM customers relative to collected revenue?

A. Yes. I have estimated the impacts on the portion of their cost to serve that the NEM customers on energy rates pay in a couple of different ways.

Assuming a retail ROR of 8.07% as APS has done (which, as mentioned above, is misrepresentative of the real world situation), but using TASC's recommended credits, NEM customers on energy rates pay 46% of their cost of service, as opposed to 36% as

[62] These demand credits have been calculated assuming all customer solar systems have a south-facing orientation. This understates the actual total demand credits that would accrue to solar customers as a whole, because some solar systems would be west facing, and would have a greater impact on peak demand, thus having a higher credit percentage applicable to them. The total demand credits in such a situation would be higher than the value presented here, but lower than if ALL solar systems were west facing.

APS has stated.[63] However, if I correct APS's revenue requirement to reflect its targeted 4.99% ROR[64] and then continue to use APS's credits, NEM customers on energy rates pay 42% of the cost to serve them. Using the same 4.99% ROR assumption and using TASC's recommended credits results in an increases to 58%.

Q. Please comment on your results.

A. Using more appropriate credits for NEM generation reduces the net cost to serve NEM customers, meaning that the shortfall between the estimated net cost of service and revenue collected from NEM customers under current rates is less than presented by APS witness Snook. The results presented above are conservative in that I assumed that all NEM systems were oriented facing due south when developing my demand credits, which results in a lower demand credits than if some NEM systems were oriented toward the west. This is consistent with the statements of TASC witness Mr. Beach, which pointed out that encouraging and incentivizing west-facing systems could improve the value of solar delivered by NEM systems.[65]

Finally, it should be noted that these estimates of net cost of service for NEM customers do not account for any of the other important direct benefits identified in TASC witness Mr. Beach's testimony, such as fuel hedging or market price mitigation, or any societal benefits.

Q. Does this complete your rebuttal testimony?

A. Yes.

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[63] Snook Testimony, p.3

[64] APS Response to Vote Solar Data Request 2.3, Attachment p. 2 of 37 – 4 of 37 (See Exhibit WAM-3).

[65] Beach Testimony, p. 24.

EXHIBIT WAM-1

RESUME FOR WILLIAM A. MONSEN

Table of Exhibits

Exhibit WAM-1: Resume of William A. Monsen

RESUME FOR WILLIAM ALAN MONSEN

PROFESSIONAL EXPERIENCE

Principal
MRW & Associates, LLC
(1989 - Present)
Specialist in electric utility generation planning, resource auctions, demand-side management (DSM) policy, power market simulation, power project evaluation, and evaluation of customer energy cost control options. Typical assignments include: analysis, testimony preparation and strategy development in large, complex regulatory intervention efforts regarding the economic benefits of utility mergers and QF participation in California's biennial resource acquisition process, analysis of markets for non-utility generator power in the western US, China, and Korea, evaluate the cost-effectiveness of onsite power generation options, sponsor testimony regarding the value of a major new transmission project in California, analyze the value of incentives and regulatory mechanisms in encouraging utility-sponsored DSM, negotiating non-utility generator power sales contract terms with utilities, and utility ratemaking.

Energy Economist
Pacific Gas & Electric Company
(1981 - 1989)
Responsible for analysis of utility and non-utility investment opportunities using PG&E's Strategic Analysis Model. Performed technical analysis supporting PG&E's Long Term Planning efforts. Performed Monte Carlo analysis of electric supply and demand uncertainty to quantify the value of resource flexibility. Developed DSM forecasting models used for long-term planning studies. Created an engineering-econometric modeling system to estimate impacts of DSM programs. Responsible for PG&E's initial efforts to quantify the benefits of DSM using production cost models.

Academic Staff
University of Wisconsin-Madison Solar Energy Laboratory
(1980 - 1981)
Developed simplified methods to analyze efficiency of passive solar energy systems. Performed computer simulation of passive solar energy systems as part of Department of Energy's System Simulation and Economic Analysis working group.

EDUCATION

M.S., Mechanical Engineering, University of Wisconsin-Madison, 1980.

B.S., Engineering Physics, University of California, Berkeley, 1977.

William A. Monsen

Prepared Testimony and Expert Reports

1. California Public Utilities Commission (California PUC) Applications 90-08-066, 90-08-067, 90-09-001
Prepared Testimony with Aldyn W. Hoekstra regarding the California-Oregon Transmission Project for Toward Utility Rate Normalization (TURN). November 29, 1990.

2. California PUC Application 90-10-003
Prepared Testimony with Mark A. Bachels regarding the Value of Qualifying Facilities and the Determination of Avoided Costs for the San Diego Gas & Electric Company for the Kelco Division of Merck & Company, Inc. December 21, 1990.

3. California Energy Commission Docket No. 93-ER-94
Rebuttal Testimony regarding the Preparation of the 1994 Electricity Report for the Independent Energy Producers Association. December 10, 1993.

4. California PUC Rulemaking 94-04-031 and Investigation 94-04-032
Prepared Testimony Regarding Transition Costs for The Independent Energy Producers. December 5, 1994.

5. Massachusetts Department of Telecommunications and Energy DTE 97-120
Direct Testimony regarding Nuclear Cost Recovery for The Commonwealth of Massachusetts Division of Energy Resources. October 23, 1998.

6. California PUC Application 97-12-039
Prepared Direct Testimony Evaluating an Auction Proposal by SDG&E on Behalf of The California Cogeneration Council. June 15, 1999.

7. California PUC Application 99-09-053
Prepared Direct Testimony of William A. Monsen on Behalf of The Independent Energy Producers Association. March 2, 2000.

8. California PUC Application 99-09-053
Prepared Rebuttal Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association. March 16, 2000.

9. California PUC Rulemaking 99-10-025
Joint Testimony Regarding Auxiliary Load Power and Stand-By Metering on Behalf of Duke Energy North America. July 3, 2000.

10. California PUC Application 99-03-014
Joint Testimony Regarding Auxiliary Load Power and Stand-By Metering on Behalf of Duke Energy North America. September 29, 2000.

11. California PUC Rulemaking 99-11-022
Testimony of the Independent Energy Producers Association Regarding Short-Run Avoided Costs. May 7, 2001.

12. California PUC Rulemaking 99-11-022
Rebuttal Testimony of the Independent Energy Producers Association Regarding Short-Run Avoided Costs. May 30, 2001.

13. California PUC Application 01-08-020
Direct Testimony on Behalf of Bear Mountain, Inc. in the Matter of Southern California Water Company's Application to Increase Rates for Electric Service in the Bear Valley Electric Customer Service Area. December 20, 2001.

14. California PUC Application 00-10-045; 01-01-044
Direct Testimony on Behalf of the City of San Diego. May 29, 2002.

15. California PUC Rulemaking 01-10-024
Prepared Direct Testimony on Behalf of Independent Energy Producers and Western Power Trading Forum. May 31, 2002.

16. California PUC Rulemaking 01-10-024
Rebuttal Testimony on Behalf of Independent Energy Producers and Western Power Trading Forum. June 5, 2002.

17. Arizona Docket Numbers E-00000A-02-0051, E-01345A-01-0822, E-0000A-01-0630, E-01933A-98-0471, E01933A-02-0069
Rebuttal Testimony on Behalf of AES NewEnergy, Inc. and Strategic Energy L.L.C.: Track A Issues. June 11, 2002.

18. California PUC Application 00-11-038
Testimony on Behalf of the Alliance for Retail Energy Markets in the Bond Charge Phase of the Rate Stabilization Proceeding. July 17, 2002.

19. California PUC Rulemaking 01-10-024
Prepared Testimony in the Renewable Portfolio Standard Phase on Behalf of Center for Energy Efficiency and Renewable Technologies. April 1, 2003.

20. California PUC Rulemaking 01-10-024
Direct testimony of William A. Monsen Regarding Long-Term Resource Planning Issues On Behalf of the City of San Diego. June 23, 2003.

21. California PUC Application 03-03-029
Testimony of William A. Monsen Regarding Auxiliary Load Power Metering Policy and Standby Rates on Behalf of Duke Energy North America. October 3, 2003.

22. California PUC Rulemaking 03-10-003
Opening Testimony of William A. Monsen Regarding Phase One Issues Related to Implementation of Community Choice Aggregation On Behalf of the Local Government Commission Coalition. April 15, 2004.

23. California PUC Rulemaking 03-10-003
Reply Testimony of William A. Monsen Regarding Phase One Issues Related to Implementation of Community Choice Aggregation on Behalf of Local Government Commission. May 7, 2004.

24. California PUC Rulemaking 04-04-003
Direct Testimony of William A. Monsen Regarding the 2004 Long-Term Resource Plan of San Diego Gas & Electric Company on Behalf of the City of San Diego. August 6, 2004.

25. Sonoma County Assessment Appeals Board
Expert Witness Report of William A. Monsen Regarding the Market Price of Electricity in the Matter of the Application for Reduction of Assessment of Geysers Power Company, LLC, Sonoma County Assessment Appeals Board, Application Nos.: 01/01-137 through 157. September 10, 2004.

26. Sonoma County Assessment Appeals Board
Presentation of Results from Expert Witness Report of William A. Monsen Regarding the Market Price of Electricity in the Matter of the Application for Reduction of Assessment of Geysers Power Company, LLC, Sonoma County Assessment Appeals Board, Application Nos.: 01/01-137 through 157. September 10, 2004.

27. Sonoma County Assessment Appeals Board
Presentation of Rebuttal Testimony and Results of William A. Monsen Regarding the Market Price of Electricity in the Matter of the Application for Reduction of Assessment of Geysers Power Company, LLC, Sonoma County Assessment Appeals Board, Application Nos.: 01/01-137 through 157. October 18, 2004.

28. California PUC Rulemaking 04-03-017
Testimony of William A. Monsen Regarding the Itron Report on Behalf of the City of San Diego. April 13, 2005.

29. California PUC Rulemaking 04-03-017
Rebuttal Testimony of William A. Monsen Regarding the Cost-Effectiveness of Distributed Energy Resources on Behalf of the City of San Diego. April 28, 2005.

30. California PUC Application 05-02-019
Testimony of William A. Monsen SDG&E's 2005 Rate Design Window Application on Behalf of the City of San Diego. June 24, 2005.

31. California PUC Rulemaking 04-01-025, Phase II
Direct Testimony of William A. Monsen on Behalf of Crystal Energy, LLC. July 18, 2005.

32. California PUC Application 04-12-004, Phase I
Direct Testimony of William A. Monsen on Behalf of Crystal Energy, LLC. July 29, 2005.

33. California PUC Application 04-12-004, Phase I
Rebuttal Testimony of William A. Monsen on Behalf of Crystal Energy, LLC. August 26, 2005.

34. California PUC Rulemakings 04-04-003 and 04-04-025
Prepared Testimony of William A. Monsen Regarding Avoided Costs on Behalf of the Independent Energy Producers. August 31, 2005.

35. California PUC Application 05-01-016 et al.
Prepared Testimony of William A. Monsen Regarding SDG&E's Critical Peak Pricing Proposal on Behalf of the City of San Diego. October 5, 2005.

36. California PUC Rulemakings 04-04-003 and 04-04-025
Prepared Rebuttal Testimony of William A. Monsen Regarding Avoided Costs on Behalf of the Independent Energy Producers. October 28, 2005.

37. Colorado PUC Docket No. 05A-543E
Answer Testimony of William A. Monsen on Behalf of AES Corporation and the Colorado Independent Energy Association. April 18, 2006.

38. California PUC Application 04-12-004
Prepared Testimony of William A. Monsen Regarding Firm Access Rights on Behalf of Clearwater Port, LLC. July 14, 2006.

39. California PUC Application 04-12-004
Prepared Rebuttal Testimony of William A. Monsen Regarding Firm Access Rights on Behalf of Clearwater Port, LLC. July 31, 2006.

40. Public Utilities Commission of Nevada Dockets 06-06051 and 06-07010
Testimony of William A. Monsen on Behalf of the Nevada Resort Association Regarding Integrated Resource Planning. September 13, 2006.

41. California PUC Application 07-01-047
Testimony of William A. Monsen on Behalf of the City of San Diego Concerning the Application of San Diego Gas & Electric Company For Authority to Update Marginal Costs, Cost Allocation, and Electric Rate Design. August 10, 2007.

42. Colorado PUC Docket No. 07A-447E
Answer Testimony of William A. Monsen on Behalf of the Colorado Independent Energy Association. April 28, 2008.

43. California PUC Application 08-02-001
Testimony of William A. Monsen On Behalf of The City of Long Beach Gas & Oil Department Concerning The Application of San Diego Gas & Electric Company And Southern California Gas Company For Authority To Revise Their Rates Effective January 1, 2009 In Their Biennial Cost Allocation Proceeding. June 18, 2008.

44. California PUC Application 08-02-001
Rebuttal Testimony of William A. Monsen On Behalf of The City of Long Beach Gas & Oil Department Concerning The Application of San Diego Gas & Electric Company And Southern California Gas Company For Authority To Revise Their Rates Effective January 1, 2009 In Their Biennial Cost Allocation Proceeding. July 10, 2008.

45. California PUC Application 08-06-001 et al.
Prepared Testimony of William A. Monsen On Behalf of The California Demand Response Coalition Concerning Demand Response Cost-Effectiveness And Baseline Issues. November 24, 2008.

46. California PUC Application 08-02-001
Testimony of William A. Monsen On Behalf of The City of Long Beach Gas & Oil Department Concerning Revenue Allocation And Rate Design Issues In The San Diego Gas & Electric Company And Southern California Gas Company Biennial Cost Allocation Proceeding. December 23, 2008.

47. California PUC Application 08-06-034
Testimony of William A. Monsen On Behalf of Snow Summit, Inc. Concerning Cost Allocation And Rate Design. January 9, 2009.

48. California PUC Application 08-02-001
Rebuttal Testimony of William A. Monsen on Behalf of The City of Long Beach Gas & Oil Department Concerning Revenue Allocation and Rate Design Issues in The San Diego Gas & Electric Company and Southern California Gas Company Biennial Cost Allocation Proceeding. January 27, 2009.

49. California PUC Application 08-11-014
Testimony of William A. Monsen on Behalf of The City of San Diego Concerning the Application of San Diego Gas & Electric Company tor Authority to Update Cost Allocation and Electric Rate Design. April 17, 2009.

50. Public Utilities Commission of the State of Colorado 09-AL-299E
Answer Testimony of William A. Monsen on Behalf of Copper Mountain, Inc. and Vail Summit Resorts, Inc. – Notice of Confidentiality: A Portion of Document Has Been Filed Under Seal. October 2, 2009.

51. Public Utilities Commission of the State of Colorado 09-AL-299E
Supplemental Answer Testimony of William A. Monsen on Behalf of Copper Mountain, Inc. and Vail Summit Resorts, Inc. October 8, 2009.

52. Public Utilities Commission of the State of Colorado Docket No. 09AL-299E
Surrebuttal Testimony of William A. Monsen on Behalf of Copper Mountain, Inc. and Vail Summit Resorts, Inc. December 18, 2009.

53. United States District Court for the District of Montana, Billings Division, Rocky Mountain Power, LLC v. Prolec GE, S De RL De CV Case No. CV-08-112-BLG-RFC, "Evaluation of Business Interruption Loss Associated with a Fault on December 15, 2007, of a Generator Step-Up (GSU) Transformer at the Hardin Generating Station, Located in Hardin, Montana," September 15, 2010.

54. United States District Court for the District of Montana, Billings Division, Rocky Mountain Power, LLC v. Prolec GE, S De RL De CV Case No. CV-08-112-BLG-RFC, "Supplemental Findings and Conclusions Regarding Evaluation of Business Interruption Loss Associated with a Fault on December 15, 2007, of a Generator Step-Up (GSU) Transformer at the Hardin Generating Station, Located in Hardin, Montana," November 2, 2010.

55. California PUC Application 10-05-006
Testimony of William Monsen on Behalf of the Independent Energy Producers Association in Track III of the Long-Term Procurement Planning Proceeding Concerning Bid Evaluation. August 4, 2011.

56. Public Service Company of Colorado Docket No. 11A-869E
Answer Testimony of William A. Monsen on Behalf of Colorado Independent Energy Association, Colorado Energy Consumers and Thermo Power & Electric LLC. June 4, 2012.

57. California PUC Application 11-10-002
Testimony of William A. Monsen on Behalf of the City of San Diego Concerning the Application of San Diego Gas & Electric Company for Authority to Update Marginal Costs, Cost Allocations, and Electric Rate Design. June 12, 2012.

58. Public Utilities Commission of the State of Colorado Docket No 11A-869E
Cross Answer Testimony of William A. Monsen on Behalf of Colorado Independent Energy Association, Colorado Energy Consumers and Thermo Power & Electric LLC. July 16, 2012.

59. California PUC Rulemaking 12-03-014
Reply Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Concerning Track One of the Long-Term Procurement Proceeding. July 23, 2012.

60. California PUC Application 12-03-026
Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association concerning Pacific Gas and Electric Company's Proposed Acquisition of the Oakley Project. July 23, 2012.

61. California PUC Application 12-02-013
Testimony of William A. Monsen on Behalf of Snow Summit, Inc. Concerning Revenue Requirement, Marginal Costs, and Revenue Allocation. July 27, 2012.

62. California PUC Application 12-03-026
Rebuttal Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Concerning Pacific Gas and Electric Company's Proposed Acquisition of the Oakley Project. August 3, 2012.

63. California PUC Application 12-02-013
Rebuttal Testimony of William A. Monsen on Behalf of Snow Summit, Inc. in Response to the Division of Ratepayer Advocates' Opening Testimony. August 27, 2012.

64. Public Utilities Commission of the State of Colorado Docket No 11A-869E
Supplemental Answer Testimony of William A. Monsen on Behalf of Colorado Independent Energy Association, Colorado Energy Consumers and Thermo Power & Electric LLC. September 14, 2012.

65. Public Utilities Commission of the State of Colorado Docket No 11A-869E
Supplemental Cross Answer Testimony of William A. Monsen on Behalf of Colorado Independent Energy Association, Colorado Energy Consumers and Thermo Power & Electric LLC. October 5, 2012.

66. Public Utilities Commission of the State Oregon Docket No UM 1182
Northwest and Intermountain Power Producers Coalition Direct Testimony of William A. Monsen. November 16, 2012.

67. Public Utilities Commission of the State Oregon Docket No UM 1182
Northwest and Intermountain Power Producers Coalition Exhibit 300 Witness
Reply Testimony of William A. Monsen. January 14, 2013.

68. California PUC Rulemaking 12-03-014
Testimony of William A. Monsen on Behalf of the Independent Energy Producers
Association Concerning Track 4 of the Long-Term Procurement Plan Proceeding.
September 30, 2013.

69. California PUC Rulemaking 12-03-014
Rebuttal Testimony of William A. Monsen on Behalf of the Independent Energy
Producers Association Concerning Track 4 of the Long-Term Procurement Plan
Proceeding. October 14, 2013.

70. California PUC Application 13-07-021
Response Testimony of William A. Monsen on Behalf of Interwest Energy
Alliance Regarding the Proposed Merger of NV Energy, Inc. with Midamerican
Energy Holdings Company. October 24, 2013.

71. California PUC Application 13-12-012
Testimony of William A. Monsen on Behalf of Commercial Energy Concerning
PG&E's 2015 Gas Transmission and Storage Rate Application. August 11, 2014.

72. Public Utilities Commission of Nevada Docket No. 14-05003
Direct Testimony of William A. Monsen on Behalf of Ormat Nevada Inc. August
25, 2014.

73. California PUC Application 13-12-012/I.14-06-016
Rebuttal Testimony of William A. Monsen on Behalf of Commercial Energy
Concerning PG&E's 2015 Gas Transmission & Storage Application. September
15, 2014.

74. California PUC Rulemaking 12-06-013
Testimony of William A. Monsen on Behalf of Vote Solar Concerning
Residential Electric Rate Design Reform. September 15, 2014.

75. CPUC Rulemaking 13-12-010
Opening Testimony of William A. Monsen on Behalf of the Independent Energy
Producers Association Regarding Phase1A of the 2014 Long-Term Procurement
Planning Proceeding. September 24, 2014.

76. CPUC Application 14-01-027
Testimony of William A. Monsen on Behalf of the City Of San Diego
Concerning the Application of SDG&E for Authority to Update Electric Rate
Design. November 14, 2014.

77. CPUC Application 14-01-027
Rebuttal Testimony of William A. Monsen on Behalf of the City Of San Diego Concerning the Application of SDG&E for Authority to Update Electric Rate Design. December 12, 2014.

78. CPUC Rulemaking 13-12-010
Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Regarding Supplemental Testimony in Phase1A of the 2014 Long-Term Procurement Planning Proceeding. December 18, 2014.

79. CPUC Application 14-06-014
Opening Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Regarding Standby Rates in Phase 2 of SCE's 2015 Test Year General Rate Case. March 13, 2015.

80. CPUC Application 14-04-014
Opening Testimony of William A. Monsen on Behalf of ChargePoint, Inc. Regarding SDG&E's Vehicle Grid Integration Pilot Program. March 16, 2015.

81. Public Utilities Commission of the State of Hawaii Docket No. 2015-0022
Direct Testimony on Behalf of AES Hawaii, Inc. July 20, 2015.

82. Federal Energy Regulatory Commission Docket Nos. EL02-60-007 and EL02-62-006 (Consolidated)
Prepared Answering Testimony of William A. Monsen on Behalf of Iberdrola Renewables Regarding Rate Impacts of the Iberdrola Contract. July 21, 2015.

83. Public Utilities Commission of Nevada Docket Nos. 15-07041 and 15-07042
Prepared Direct Testimony of William A. Monsen On Behalf of The Alliance for Solar Choice (TASC). October 27, 2015.

Exhibit WAM-2: APS Responses to TASC Data Requests

This Exhibit includes the following Data Responses: TASC DR 1.15, 4.1, and 4.4
(Note: Response to DR 1.15 includes feeder data that has not been included
here. It can be provided on request.

TASC'S FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER
REGARDING THE COMMISSION'S INVESTIGATION OF
VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET NO. E-00000J-14-0023
JANUARY 26, 2016

TASC 1.15: Please provide, in Excel format, hourly load data, for the most recent historical year for which data is available, for a representative sample of distribution feeders on the APS system.

Response: APS is gathering this information and will provide a response as soon as possible.

TASC'S FOURTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION DOCKET E-00000J-14-0023 MARCH 14, 2016

TASC 4.1: Please provide hourly loads for all of APS's residential customers for 2014 and 2015 in Excel format. In addition, please provide hourly loads for the following subsets of residential customers:

a. Customers participating in APS's energy efficiency programs;

b. Customers participating in APS's demand response programs;

c. Customers located in the city limits of Phoenix;

d. Customers located in the Phoenix metropolitan area;

e. Customers with rooftop solar;

f. Customers that do not have central air conditioning;

g. Customers that have swimming pools;

h. Customers that have setback thermostats that control their air conditioners;

i. Customers that are dual fuel customers (as discussed on page 26 of Mr. Snook's testimony);

j. Customers living in apartments (as discussed on page 25 of Mr. Snook's testimony);

k. Customers that are "empty nesters" (as discussed on page 25-26 of Mr. Snook's testimony).

For each set of hourly loads, please indicate the average number of customers included in each set.

Response: Hourly loads for each of APS's 1.1 million residential customers would consist of over 9.5 million data points annually, and is too voluminous to provide. However, APS is providing as APS15876 the total hourly load for 2014 for customers on each residential rate APS offers. These loads are disaggregated by each load type used by APS in the 2014 Cost of Service Study as discussed in APS Witness Snook's direct testimony. APS15876 also provides customer counts for each of the load types. Additionally, please see APS15871, provided in the Company's response to TASC Question 3.2, for average hourly loads for dual fuel, winter visitor, and apartment customers for 2014 as discussed in Mr. Snook's testimony. If average per customer loads are desired, please divide the total hourly loads by the customer count provided.

TASC'S FOURTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION DOCKET E-00000J-14-0023 MARCH 14, 2016

TASC 4.1 Supplemental Response:

a - b. APS does not possess hourly load data for energy efficiency and demand response participants as the Company's customer information system (CIS) does not track these customers.

c – d. APS objects to this request as unduly burdensome and seeking irrelevant information that is not likely to lead to the discovery of admissible evidence. Further, no documents exist with this information. Although APS's customer information system does contain the zip codes in which customers live, any document showing this information would have to be created through targeted queries to its database, compilation of data, and organization and labeling of data into an understandable Excel format.

e. Please see APS15876 for total hourly loads and customer counts of customers with rooftop solar, from which an average hourly load can be easily derived.

f – h. APS does not possess hourly load data for central air conditioning, swimming pools, or setback thermostat customers as the Company's CIS does not track these customers.

i – j. Please see APS15878, provided in the Company's second supplemental response to TASC Question 3.2, for average hourly loads for dual fuel customers and apartment dwellers.

k. APS does not possess hourly load data for "empty nesters", as CIS does not track these customers.

TASC'S FOURTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET E-00000J-14-0023
MARCH 14, 2016

TASC 4.4: Is APS aware of any instances in which power flows from residential NEM systems interconnected at the secondary distribution voltage level have resulted in power being backfed onto APS's transmission system? If your response is anything except for an unqualified "no," please provide data indicating precisely when such backfeeding occurred and the costs incurred by APS as a result of that backfeeding.

Response: APS is not currently aware of any power backfed into APS's transmission system solely from residential NEM systems; however, APS is aware of several distribution feeders that have experienced reverse flow directly due to residential NEM systems.

Attached as APS15879 is a table showing APS's top 25 distribution feeders by interconnected residential NEM systems and the number of NEM systems connected to each. The eleven feeders that experienced reverse power flow in 2015 are designated in yellow.

To date, APS has not incurred equipment or system costs directly attributable to these reverse power flows. Given the increasing penetration of rooftop solar, however, APS anticipates that the severity of reverse power flows will only increase.

Reverse Power Flows in 2015 – Highest System Count NEM Distribution Feeders				
Feeder	**NEM System Count**	**Lowest 15 Min**	**Lowest 15 Min 2015 (MWs)**	**Total Hours of Reverse Flow**
1	848	5/8 @ 12:45	-0.9368	328.75
2	702	1/16 @ 13:15	0.0005	
3	689	5/9 @ 12:45	-2.0783	935.50
4	467	4/16 @ 13:00	-0.6794	133.25
5	451	5/8 @ 12:45	-0.5829	49.75
6	409	5/8 @ 12:45	-0.4658	184.50
7	402	3/15 @ 12:30	1.1599	
8	353	4/16 @ 10:30	0.0203	
9	338	8/7 @ 19:45	-0.0008	18.00
10	331	9/29 @ 10:15	-0.0011	2.25
11	324	10/8 @ 13:15	1.2314	
12	322	5/8 @ 13:30	-0.1282	15.75
13	284	11/17 @ 13:00	0.8633	
14	274	11/6 @ 13:30	0.8384	
15	268	4/16 @ 12:30	0.4930	
16	260	4/16 @ 12:30	0.6152	
17	258	11/5 @ 12:15	0.7298	
18	253	5/8 @ 13:45	-0.1101	29.00
19	229	4/27 @ 11:15	-0.0020	0.50
20	228	6/10 @ 9:15	0.0008	
21	224	4/16 @ 12:30	0.1960	
22	208	11/9 @ 10:15	1.0964	
23	202	9/2 @ 3:30	4.5452	
24	194	9/23 @ 3:00	2.2743	
25	189	3/9 @ 13:15	-0.0927	1.50

Exhibit WAM-3: APS Responses to Vote Solar Data Requests

This Exhibit includes the following Data Responses: Vote Solar DR 1.1, 2.1, 2.3, and 2.4

2014 Allocation Factor Input Page

Line No.	Customer Class	# of Customers	Energy Consumption (MWH)	Delivery Level %	CP (kW)	4CP (kW)	12CP (kW)	NCP (kW)	Ind. Max (kW)	Delivery Level %	Line No.
	Residential										
0	Residential - Solar Site (Energy Rates)	27,078	369,769		122,495	112,553	73,588	122,816	198,649		0
0	Residential - Solar Site (Demand Rates)	1,176	25,432		7,536	6,954	4,696	7,568	11,693		0
1	E-12 (No Solar)	468,372	3,579,549		947,566	865,097	647,709	1,106,357	2,137,411		1
2	ET-1 (No Solar)	140,698	2,328,525		706,794	637,055	439,842	802,832	1,176,152		2
3	ECT-1R (No Solar)	27,488	726,448		199,141	179,779	127,494	212,342	309,249		3
4	ET-2 (No Solar) w/ET-SP	288,729	4,030,856		1,172,586	1,080,109	751,280	1,341,792	2,168,198		4
5	ECT-2 (No Solar)	91,248	2,020,487		552,582	510,485	353,463	608,438	907,202		5
6	**Total Residential**	**1,044,789**	**13,081,066**		**3,708,700**	**3,392,032**	**2,398,072**	**4,202,145**	**6,908,554**		**6**
	General Service										
7	**E-20**	409	38,842		11,200	8,900	6,517	22,943	28,136		7
8	E-30,E-32 0-20kW	106,780	1,432,985		270,400	262,350	239,683	341,726	548,276		8
9	E-32 21-100kW	14,494	2,572,375		538,400	508,725	399,317	636,796	847,773		9
10	Total E-30, E-32 0-100kW	121,274	4,005,360		808,800	771,075	639,000	978,522	1,396,049		10
11	Total E-30, E-32 0-100kW @ Dist. Primary	53		0.001700					2,351	0.001684	11
12	Total E-30, E-32 0-100kW @ Secondary Txf	121,221		0.998300					1,393,698	0.998316	12
13	Total E-32 101-400kW	4,252	3,188,803		550,900	509,900	440,242	628,994	814,527		13
14	Total E-32 101-400kW @ Dist. Primary	35		0.012000					12,873	0.015804	14
15	Total E-32 101-400kW @ Secondary Txf	4,217		0.988000					801,654	0.984196	15
16	Total E-32 401-999kW	694	1,699,183		261,900	239,900	226,667	298,642	353,653		16
17	Total E-32 1,000+kW	101	1,188,116		184,000	158,750	123,558	195,966	244,300		17
18	Total E-32 401+kW	795	2,887,299	-	445,900	398,650	350,225	494,608	597,953		18
19	Total E-32 401+kW @ Transmission Level	5		0.005000					3,745	0.006263	19
20	Total E-32 401+kW @ Dist. Primary	57		0.132800					100,227	0.167617	20
21	Total E-32 401+kW @ Secondary Txf	733		0.862200					493,981	0.826120	21
22	**Total E-30,E-32**	126,321	10,081,462		1,805,600	1,679,625	1,429,467	2,102,124	2,808,529		22
23	E-32 TOU 0-20kW	204	3,519		500	500	583	837	1,384		23
24	E-32 TOU 21-100kW	132	34,740		5,000	4,550	4,133	5,788	8,100		24
25	Total E-32 TOU 0-100kW	336	38,259		5,500	5,050	4,716	6,625	9,484		25
26	Total E-32 TOU 0-100kW @ Dist. Primary	1		0.003200					50	0.005272	26
27	Total E-32 TOU 0-100kW @ Secondary Txf	335		0.996800					9,434	0.994728	27
28	E-32 TOU 101-400kW	73	70,694		10,800	10,200	9,000	11,666	15,770		28
	Total E-32 TOU 101-400kW @ Dist. Primary			0.114800					2,729	0.173050	
	Total E-32 TOU 101-400kW @ Secondary Txf			0.885200					13,041	0.826950	
29	E-32 TOU 401-999kW	43	132,818		18,500	16,200	14,992	19,860	24,674		29
30	E-32 TOU 1000+kW	14	131,780		15,200	16,525	15,467	23,900	30,200		30
31	Total E-32 TOU 401+kW	57	264,598		33,700	32,725	30,459	43,760	54,874		31
32	Total E-32 TOU 401+kW @ Dist. Primary	10		0.192100					9,110	0.166017	32
33	Total E-32 TOU 401+kW @ Secondary Txf	47		0.807900					45,764	0.833983	33
34	**Total E-32 TOU**	466	373,551		50,000	47,975	44,175	62,051	80,128		34
35	**General Service School TOU**	116	110,696		15,200	16,150	14,808	36,939	40,172		35
36	**Total E-34**	30	881,656		143,500	137,475	117,150	152,848	171,923		36
37	Total E-34 @ Transmission Level	3		0.138300					21,468	0.124870	37
38	Total E-34 @ Dist. Substation	-		0.000000					-	0.000000	38
39	Total E-34 @ Dist. Primary	18		0.652700					101,289	0.589153	39
40	Total E-34 @ Secondary Txf	9		0.209000					49,166	0.285977	40
41	**Total E-35**	37	2,127,615		255,500	255,400	245,900	288,761	336,110		41
42	Total E-35 @ Transmission Level	3		0.084300					20,189	0.060067	42
43	Total E-35 @ Dist. Substation	-		0.000000					-	0.000000	43
44	Total E-35 @ Dist. Primary	13		0.423200					101,332	0.301485	44
45	Total E-35 @ Secondary Txf	21		0.492500					214,589	0.638449	45
46	**Total General Service**	**127,379**	**13,613,822**		**2,281,000**	**2,145,525**	**1,858,017**	**2,665,666**	**3,464,998**		**46**
47	E-221	1,467	346,679		42,500	40,175	36,475	73,365	123,951		47
48	STREETLIGHTS	1,023	142,665		-	-	8,250	33,000	33,000		48
49	DUSK TO DAWN	8,319	22,969		-	-	1,325	5,300	5,300		49
50	**Total ACC**	**1,182,977**	**27,207,201**		**6,032,200**	**5,577,732**	**4,302,139**	**6,979,476**	**10,535,803**		**50**

2014 Allocation Factor Input Page

ENERGY Line Loss Values		DEMAND Line Loss Values	
1.01300	(3) to (4)	1.01900	(3) to (4)
1.00900	(4) to (5)	1.01300	(4) to (5)
1.01800	(5) to (6)	1.02600	(5) to (6)
1.00200	(6) to (7)	1.00300	(6) to (7)
1.00906	(7) to (8)	1.01201	(7) to (8)
1.02503	(8) to (9)	1.01888	(8) to (9)
1.07837		1.09532	

Revenue Credit Customers							
BHP MINERAL	1	49,918	9,800	5,225	5,942	15,200	15,200
MEXICO TAP BOSE	1	26,014	4,400	4,325	3,317	4,700	4,700
MEXICO TAP DEMDA	1	1,025	100	150	117	700	700
MEXICO TAP MECOX	1	1,344	300	250	200	500	500
MEXICO TAP PAULSON	1	4,594	900	900	667	1,300	1,300
SOLANA PLANT	1	34,343	-	-	2,958	20,100	20,100
DUKE ARLINGTON	1	16,331	-	-	183	17,000	17,000
HARQUAHALA PLANT	1	16,340	-	-	1,542	11,200	11,200
MESQUITE PLANT	1	2,658	-	-	158	9,600	9,600
PANDA PLANT	1	24,653	-	-	500	18,100	18,100
Total Revenue Credit Customers	10	177,420	15,500	10,850	15,584	98,400	98,400
	1,182,987	27,384,621	6,047,700	5,588,582	4,317,723	7,077,876	10,634,203
Residential - E-12 Solar Delivered	10,305	72,787	26,734	22,478	15,974	32,422	54,700
Residential - ET-1 Solar Delivered	5,119	61,194	21,906	18,645	12,800	25,898	39,869
Residential - ET-2 Solar Delivered	11,654	133,231	46,214	40,016	27,395	56,417	85,326
Residential - Solar Delivered (Energy Rates)	27,078	267,212	94,854	81,139	56,169	114,737	179,895
Residential - E-12 Solar Net	10,305	10,781	24,553	18,850	13,240	32,422	54,700
Residential - ET-1 Solar Net	5,119	29,873	21,273	17,434	11,808	25,898	39,869
Residential - ET-2 Solar Net	11,654	70,642	44,913	37,487	25,338	56,417	85,326
Residential - Solar Net (Energy Rates)	27,078	111,296	90,739	73,771	50,386	114,737	179,895
Residential - ECT-1 Solar Delivered	355	6,917	2,259	1,921	1,364	2,575	3,831
Residential - ECT-2 Solar Delivered	821	12,775	3,918	3,465	2,437	4,799	7,083
Residential - Solar Delivered (Demand Rates)	1,176	19,692	6,177	5,386	3,801	7,374	10,914
Residential - ECT-1 Solar Net	355	4,827	2,235	1,868	1,318	2,575	3,831
Residential - ECT-2 Solar Net	821	8,766	3,851	3,324	2,318	4,798	7,083
Residential - Solar Net (Demand Rates)	1,176	13,593	6,086	5,190	3,636	7,373	10,914
Residential - E-12 Solar Received	-	62,006	2,181	3,628	2,734	-	-
Residential - ET-1 Solar Received	-	31,321	633	1,211	992	-	-
Residential - ET-2 Solar Received	-	62,589	1,301	2,529	2,057	-	-
Residential - Solar Received (Energy Rates)	-	155,916	4,115	7,368	5,783	-	-
Residential - ECT-1 Solar Received	-	2,090	24	55	46	-	-
Residential - ECT-2 Solar Received	-	4,009	67	141	119	1	-
Residential - Solar Received (Demand Rates)	-	6,099	91	196	165	1	-
Residential - E-12 Solar Site	10,305	105,638	35,929	32,860	21,683	35,929	61,904
Residential - ET-1 Solar Site	5,119	82,880	27,748	25,227	16,476	27,748	43,617
Residential - ET-2 Solar Site	11,654	181,251	58,818	54,466	35,429	59,139	93,128
Residential - Solar Site (Energy Rates)	27,078	369,769	122,495	112,553	73,588	122,816	198,649
Residential - E-12 Solar Delivered	10,305	72,787	26,734	22,478	15,974	32,422	54,700
Residential - ET-1 Solar Delivered	5,119	61,194	21,906	18,645	12,800	25,898	39,869
Residential - ET-2 Solar Delivered	11,654	133,231	46,214	40,016	27,395	56,417	85,326
Residential - Solar Delivered (Energy Rates)	27,078	267,212	94,854	81,139	56,169	114,737	179,895
Residential - ECT-1 Solar Site	355	8,649	2,651	2,376	1,623	2,658	4,046
Residential - ECT-2 Solar Site	821	16,783	4,885	4,578	3,073	4,910	7,647
Residential - Solar Site (Demand Rates)	1,176	25,432	7,536	6,954	4,696	7,568	11,693
Residential - ECT-1 Solar Delivered	355	6,917	2,259	1,921	1,384	2,575	3,831
Residential - ECT-2 Solar Delivered	821	12,775	3,918	3,465	2,437	4,799	7,083
Residential - Solar Delivered (Demand Rates)	1,176	19,692	6,177	5,386	3,801	7,374	10,914
Residential - E-12 Solar (Customer Usage)		32,851	9,195	10,382	5,709	3,507	7,204
Residential - ET-1 Solar (Customer Usage)		21,686	5,842	6,582	3,676	1,850	3,748
Residential - ET-2 Solar (Customer Usage)		48,020	12,604	14,450	8,034	2,722	7,802
Residential - Solar (Customer Usage)(Energy Rates)		102,557	27,641	31,414	17,419	8,079	18,754
Residential - ECT-1 Solar (Customer Usage)		1,732	392	455	259	83	215
Residential - ECT-2 Solar (Customer Usage)		4,008	967	1,113	636	111	564
Residential - Solar (Customer Usage)(Demand Rates)		5,740	1,359	1,568	895	194	779
Residential - E-12 Total Solar Generation		94,857	11,376	14,010	8,443	3,507	7,204
Residential - ET-1 Solar Generation		53,007	6,475	7,793	4,668	1,850	3,748
Residential - ET-2 Solar Generation		110,609	13,905	16,979	10,091	2,722	7,802
Residential - Solar Generation (Energy Rates)		258,473	31,756	38,782	23,202	8,079	18,754
Residential - ECT-1 Solar Generation		3,822	416	510	305	83	215
Residential - ECT-2 Solar Generation		8,017	1,034	1,254	755	112	564
Residential - Solar Generation (Demand Rates)		11,839	1,450	1,764	1,060	195	779

VOTE SOLAR'S SECOND SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER REGARDING THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET NO. E-00000J-14-0023
JANUARY 4, 2016

Vote Solar 2.1: Regarding APS's October 8, 2015 Cost of Service letter filed in Docket No. E-01345A-13-0248:

On page 2 of APS's October 8, 2015 Cost of Service letter, the Company provided a chart depicting the "Cost of Service Results for A Typical Solar Customer." Please provide all workpapers supporting this chart, including linked references to the Cost of Service Working Model provided by APS in response to VS 1.1.

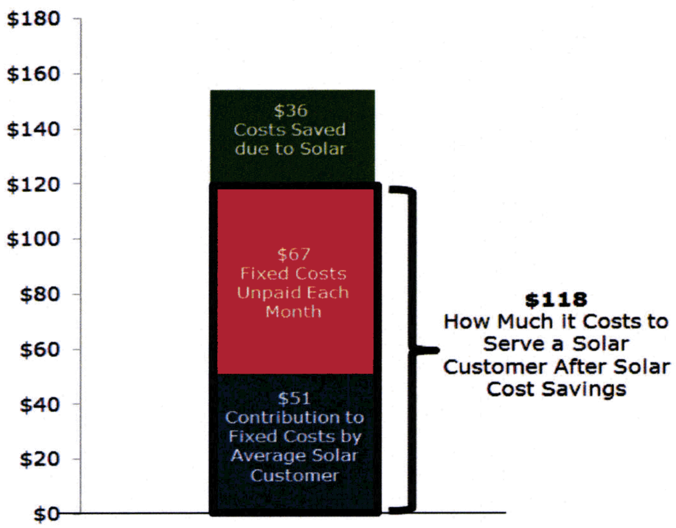
Response: See attached as APS15767 for the workpapers supporting this chart.

Back-Up for Chart:

	(A) Total Monthly Cost to Serve Typical Solar Customer	(B) What Solar Customers Should Pay	(C) What Solar Customers are Actually Paying	(D) Unrecovered Amount (Column B-C)
Base Cost to Serve a Customer	$136	$104	$44	$61
Adjustors	$18	$14	$8	$6
Total	$154	$118	$51	$67

Costs Saved due to Solar	$36

Cost of Service Results for A Typical Solar Customer



Residential Solar @ Actual ROR (Energy Rates - SITE)

Unbundled Functional Revenue Requirement after Energy and Demand Credits

		Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
	Rate Base												
1)	Rate Base (excluding Cust. Advances & Deposits)	$51,451,369	$1,356,802	$0	$6,216,972	$26,756,298	$20,811,249	$0	$4,840,752	$0	$0	$3,019,457	$114,452,899
2)	Customer Accounts							$1,794,234		$107,877	$121,842		$2,023,953
3)	Cust. Service & Info and Sales Expense							$580,497					$580,497
4)	Customer Deposits				(42,827)	(184,236)	(143,295)						(370,358)
5)	Customer Advances	(15,924)			(71,725)	(308,550)	(239,982)						($636,181)
6)	Total Rate Base	$51,435,445	$1,356,802	$0	$6,102,420	$26,263,512	$20,427,972	$2,374,732	$4,840,752	$107,877	$121,842	$3,019,457	$116,050,810
7)	Actual Earned ROR @ -5.36%												
8)	Return on Rate Base (Line 6 * Line 7)	($2,759,039)	($72,780)	$0	($327,339)	($1,408,796)	($1,095,773)	($127,383)	($259,662)	($5,787)	($6,536)	($161,966)	($6,225,060)
	Computation of Income Taxes												
9)	Weighted Cost of Long Term Debt @ 2.49%												
10)	Tax Rate @ 39.19%												
11)	Income Taxes ((Line 7-Line 9)(Line 6)(Line 10))/(1-Line 10)	($2,603,557)	($68,679)	$0	($308,892)	($1,329,405)	($1,034,022)	($120,204)	($245,029)	($5,460)	($6,167)	($152,839)	($5,874,254)
	Expenses												
12)	Expenses	$8,029,855	$9,637,630	$3,561,494	$567,284	$2,791,108	$2,038,147	$0	$1,337,751	$0	$0	$1,208,737	$29,172,005
13)	Customer Accounts	$0	$0	$0	$0	$0	$0	$1,533,621	$0	$304,642	$115,894	$0	$1,954,157
14)	Cust. Service & Info and Sales Expense	$0	$0	$0	$0	$0	$0	$700,635	$0	$0	$0	$0	$700,635
15)	Total Expenses	$8,029,855	$9,637,630	$3,561,494	$567,284	$2,791,108	$2,038,147	$2,234,257	$1,337,751	$304,642	$115,894	$1,208,737	$31,826,798
	Revenue Requirement												
16)	Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$2,667,259	$9,496,171	$3,561,494	($68,947)	$52,906	($91,648)	$1,986,670	$833,061	$293,395	$103,191	$893,932	$19,727,483
17)	Less: Revenue Credits	$1,598,373	$2,733,994	$847,066	$35,400	$201,831	$125,584	$9,763	$22,010	$0	$0	$0	$5,574,020
18)	**REVENUE REQUIREMENT @-5.36%**	**$1,068,886**	**$6,762,177**	**$2,714,428**	**($104,347)**	**($148,925)**	**($217,232)**	**$1,976,907**	**$811,050**	**$293,395**	**$103,191**	**$893,932**	**$14,153,463**
19)	**Energy Consumption (MWh)**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**
20)	**Functional Unit Costs (cents/kWh)**	**0.0040**	**0.0253**	**0.0102**	**-0.0004**	**-0.0006**	**-0.0008**	**0.0074**	**0.0030**	**0.0011**	**0.0004**	**0.0033**	**0.0530**
21)	**Number of Customers**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**
22)	**Functional Unit Costs ($/Customer/month)**	**$3.29**	**$20.81**	**$8.35**	**-$0.32**	**-$0.46**	**-$0.67**	**$6.08**	**$2.50**	**$0.90**	**$0.32**	**$2.75**	**$43.56**

Residential Solar @ Targeted ROR (Energy Rates - SITE)

Unbundled Functional Revenue Requirement after Energy and Demand Credits

		Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
	Rate Base												
1)	Rate Base (excluding Cust. Advances & Deposits)	$51,451,369	$1,356,802	$0	$6,216,972	$26,756,298	$20,811,249		$4,840,752			$3,019,457	$114,452,899
2)	Customer Accounts							1,794,234		107,877	121,842		$2,023,953
3)	Cust. Service & Info and Sales Expense							$580,497					$580,497
4)	Customer Deposits				(42,827)	(184,236)	(143,295)						(370,358)
5)	Customer Advances	(15,924)			(71,725)	(308,550)	(239,982)						($636,181)
6)	Total Rate Base	$51,435,445	$1,356,802	$0	$6,102,420	$26,263,512	$20,427,972	$2,374,732	$4,840,752	$107,877	$121,842	$3,019,457	$116,050,810
7)	Targeted ROR @ 4.99%												
8)	Return on Rate Base (Line 6 * Line 7)	$2,566,629	$67,704	$0	$304,511	$1,310,549	$1,019,356	$118,499	$241,554	$5,383	$6,080	$150,671	$5,790,935
	Computation of Income Taxes												
9)	Weighted Cost of Long Term Debt @ 2.49%												
10)	Tax Rate @ 39.19%												
11)	Income Taxes ((Line 7-Line 9)(Line 6)(Line 10))/(1-Line 10)	$828,727	$21,861	$0	$98,322	$423,157	$329,135	$38,262	$77,994	$1,738	$1,963	$48,649	$1,869,809
	Expenses												
12)	Expenses	8,029,855	9,637,630	3,561,494	567,284	2,791,108	2,038,147		$1,337,751			$1,208,737	$29,172,005
13)	Customer Accounts							1,533,621		304,642	115,894		$1,954,157
14)	Cust. Service & Info and Sales Expense							$700,635					$700,635
15)	Total Expenses	$8,029,855	$9,637,630	$3,561,494	$567,284	$2,791,108	$2,038,147	$2,234,257	$1,337,751	$304,642	$115,894	$1,208,737	$31,826,798
	Revenue Requirement												
16)	Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$11,425,211	$9,727,195	$3,561,494	$970,116	$4,524,814	$3,386,638	$2,391,017	$1,657,299	$311,763	$123,937	$1,408,057	$39,487,542
17)	Less: Revenue Credits	$1,598,373	$2,733,994	$847,066	$35,400	$201,831	$125,584	$9,763	$22,010	$0	$0	$0	$5,574,020
18)	**REVENUE REQUIREMENT @4.99%**	**$9,826,838**	**$6,993,201**	**$2,714,428**	**$934,717**	**$4,322,984**	**$3,261,054**	**$2,381,255**	**$1,635,289**	**$311,763**	**$123,937**	**$1,408,057**	**$33,913,522**
19)	**Energy Consumption (MWh)**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**
20)	**Functional Unit Costs (cents/kWh)**	**0.0368**	**0.0262**	**0.0102**	**0.0035**	**0.0162**	**0.0122**	**0.0089**	**0.0061**	**0.0012**	**0.0005**	**0.0053**	**0.1269**
21)	**Number of Customers**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**
22)	**Functional Unit Costs ($/Customer/month)**	**$30.24**	**$21.51**	**$8.35**	**$2.88**	**$13.30**	**$10.04**	**$7.33**	**$5.03**	**$0.96**	**$0.38**	**$4.33**	**$104.36**
23)	**Under Recovery (Targeted less Actual)($/Cust/Month)**	**$26.95**	**$0.70**	**$0.00**	**$3.20**	**$13.76**	**$10.70**	**$1.24**	**$2.54**	**$0.06**	**$0.06**	**$1.58**	**$60.80**

Residential Targeted ROR	**Weighted Residential ROR**
Rate Base	$ [illegible]
Operating Income	[illegible]
Current Rate of Return	[illegible]

Residential Solar @ Actual ROR (Energy Rates - SITE)

Unbundled Functional Revenue Requirement before Energy Credits

		Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
	Rate Base												
1)	Rate Base (excluding Cust. Advances & Deposits)	$51,451,369	$1,356,802		$6,216,972	$26,756,298	$20,811,249	$0	$4,840,752			$3,019,457	$114,452,899
2)	Customer Accounts							$1,794,234		$107,877	$121,842		$2,023,953
3)	Cust. Service & Info and Sales Expense							$580,497					$580,497
4)	Customer Deposits				($42,810)	($184,243)	($143,305)						(370,358)
5)	Customer Advances	($15,924)			($71,696)	($308,560)	($240,001)						($636,181)
6)	Total Rate Base	$51,435,445	$1,356,802	$0	$6,102,466	$26,263,495	$20,427,943	$2,374,731	$4,840,752	$107,877	$121,842	$3,019,457	$116,050,810
7)	Actual Earned ROR @ -10.77%												
8)	Return on Rate Base (Line 6 * Line 7)	($5,539,575)	($146,127)	$0	($657,233)	($2,828,567)	($2,200,080)	($255,757)	($521,347)	($11,618)	($13,122)	($325,194)	($12,498,621)
	Computation of Income Taxes												
9)	Weighted Cost of Long Term Debt @ 2.49%												
10)	Tax Rate @ 39.19%												
11)	Income Taxes ((Line 7-Line 9)(Line 6)(Line 10))/(1-Line 10)	($4,395,555)	($115,949)	$0	($521,503)	($2,244,418)	($1,745,725)	($202,939)	($413,680)	($9,219)	($10,412)	($258,036)	($9,917,435)
	Expenses												
12)	Expenses	10,277,250	17,706,894	3,561,494	$567,284	$2,791,108	$2,038,147		$1,337,751			$1,208,737	$39,488,665
13)	Customer Accounts							$1,533,621		$304,642	$115,894		$1,954,157
14)	Cust. Service & Info and Sales Expense							$700,635					$700,635
15)	Total Expenses	$10,277,250	$17,706,894	$3,561,494	$567,284	$2,791,108	$2,038,147	$2,234,256	$1,337,751	$304,642	$115,894	$1,208,737	$42,143,457
	Revenue Requirement												
16)	Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$342,121	$17,444,818	$3,561,494	($611,452)	($2,281,877)	($1,907,658)	$1,775,559	$402,725	$283,805	$92,359	$625,507	$19,727,401
17)	Less: Revenue Credits	$1,598,373	$2,733,994	$847,066	$35,400	$201,831	$125,584	$9,763	$22,010	$0	$0	$0	$5,574,021
18)	**REVENUE REQUIREMENT @-10.77%**	**($1,256,252)**	**$14,710,824**	**$2,714,428**	**($646,852)**	**($2,483,708)**	**($2,033,242)**	**$1,765,796**	**$380,715**	**$283,805**	**$92,359**	**$625,507**	**$14,153,380**
19)	**Energy Consumption (MWh)**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**
20)	**Functional Unit Costs (cents/kWh)**	**-0.0047**	**0.0551**	**0.0102**	**-0.0024**	**-0.0093**	**-0.0076**	**0.0066**	**0.0014**	**0.0011**	**0.0003**	**0.0023**	**0.0530**
21)	**Number of Customers**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**
22)	**Functional Unit Costs ($/Customer/month)**	**-$3.87**	**$45.27**	**$8.35**	**-$1.99**	**-$7.64**	**-$6.26**	**$5.43**	**$1.17**	**$0.87**	**$0.28**	**$1.93**	**$43.56**

Residential Solar @ Targeted ROR (Energy Rates - SITE)

Unbundled Functional Revenue Requirement

		Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
	Rate Base												
1)	Rate Base (excluding Cust. Advances & Deposits)	$51,451,369	$1,356,802		$6,216,972	$26,756,298	$20,811,249		$4,840,752			$3,019,457	$114,452,899
2)	Customer Accounts							1,794,234		107,877	121,842		$2,023,953
3)	Cust. Service & Info and Sales Expense							$580,497					$580,497
4)	Customer Deposits				(42,810)	(184,243)	(143,305)						(370,358)
5)	Customer Advances	(15,924)			(71,696)	(308,560)	(240,001)						($636,181)
6)	Total Rate Base	$51,435,445	$1,356,802	$0	$6,102,466	$26,263,495	$20,427,943	$2,374,731	$4,840,752	$107,877	$121,842	$3,019,457	$116,050,810
7)	Targeted ROR @ 4.99%												
8)	Return on Rate Base (Line 6 * Line 7)	$2,566,629	$67,704	$0	$304,513	$1,310,548	$1,019,354	$118,499	$241,554	$5,383	$6,080	$150,671	$5,790,935
	Computation of Income Taxes												
9)	Weighted Cost of Long Term Debt @ 2.49%												
10)	Tax Rate @ 39.19%												
11)	Income Taxes ((Line 7-Line 9)(Line 6)(Line 10))/(1-Line 10)	$828,727	$21,861	$0	$98,323	$423,157	$329,135	$38,262	$77,994	$1,738	$1,963	$48,649	$1,869,809
	Expenses												
12)	Expenses	10,277,250	17,706,894	3,561,494	567,284	2,791,108	2,038,147		$1,337,751			$1,208,737	$39,488,665
13)	Customer Accounts							1,533,621		304,642	115,894		$1,954,157
14)	Cust. Service & Info and Sales Expense							$700,635					$700,635
15)	Total Expenses	$10,277,250	$17,706,894	$3,561,494	$567,284	$2,791,108	$2,038,147	$2,234,256	$1,337,751	$304,642	$115,894	$1,208,737	$42,143,457
	Revenue Requirement												
16)	Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$13,672,606	$17,796,459	$3,561,494	$970,120	$4,524,814	$3,386,636	$2,391,017	$1,657,299	$311,763	$123,937	$1,408,057	$49,804,202
17)	Less: Revenue Credits	$1,598,373	$2,733,994	$847,066	$35,400	$201,831	$125,584	$9,763	$22,010	$0	$0	$0	$5,574,021
18)	**REVENUE REQUIREMENT @4.99%**	**$12,074,233**	**$15,062,465**	**$2,714,428**	**$934,720**	**$4,322,983**	**$3,261,052**	**$2,381,254**	**$1,635,289**	**$311,763**	**$123,937**	**$1,408,057**	**$44,230,181**
19)	**Energy Consumption (MWh)**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**
20)	**Functional Unit Costs (cents/kWh)**	**0.0452**	**0.0564**	**0.0102**	**0.0035**	**0.0162**	**0.0122**	**0.0089**	**0.0061**	**0.0012**	**0.0005**	**0.0053**	**0.1655**
21)	**Number of Customers**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**
22)	**Functional Unit Costs ($/Customer/month)**	**$37.16**	**$46.35**	**$8.35**	**$2.88**	**$13.30**	**$10.04**	**$7.33**	**$5.03**	**$0.96**	**$0.38**	**$4.33**	**$136.11**
23)	**Under Recovery (Targeted less Actual)[$/Cust/Month]**	**$41.02**	**$1.07**	**$0.00**	**$4.87**	**$20.95**	**$16.29**	**$1.89**	**$3.86**	**$0.09**	**$0.10**	**$2.41**	**$92.55**

Note: The target ROR of 4.99% is the average residential non-solar ROR.

	Demand Credit	Energy Credit
Line 12 before credits	**$10,277,250**	**$17,706,894**
Line 12 after credits	**$8,029,855**	**$9,637,630**
Difference is the credits	**($2,247,395)**	**($8,069,264)**

Residential Targeted ROR	**Weighted Residential ROR**
Rate Base	**$ 3,856,821,439**
Operating Income	**192,487,886**
Current Rate of Return	4.99%

VOTE SOLAR'S SECOND SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER REGARDING THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION DOCKET NO. E-00000J-14-0023 JANUARY 4, 2016

Vote Solar 2.3: Regarding APS's October 8, 2015 Cost of Service letter filed in Docket No. E-01345A-13-0248:

On page 2 of APS's October 8, 2015 Cost of Service letter, the Company stated that its cost of service study "incorporates and credits to solar customers the measurable costs that APS avoids when a customer installs rooftop solar."

a) Please list the categories of avoided costs that APS incorporated into its cost of service study.

b) Please describe the methodology APS used to calculate each category of avoided costs listed in response to subquestion (a).

c) For each category of avoided costs listed in response to subquestion (a), please describe where the Cost of Service Working Model provided in response to VS 1.1 calculates each avoided cost.

Response: a & b. In the cost of service study, the avoided costs for which APS credited solar customers are:

- A "Production Demand Credit" which provides the solar customers with a credit for their reduced demand on APS's system. This was calculated by taking the total megawatts APS delivers to the customer as a percent of the customer's total site load (see APS's response to VS 2.4.c 'Solar Site' for a description of this term) for both non-coincident and coincident peak during the 4 system peak months of the year (June-September). This is consistent with the "average and excess" method of allocating production demand cost required by the ACC. This then derived a blended average that credits the solar customers for offsetting a portion of APS's peak load. The total amount credited for solar energy customers was $2.2M (or a reduction of 18.66% in their production demand cost) and for solar demand customers it was $109k (or a reduction of 14.64% in their production demand cost). See APS15768.

- An "Energy Fuel Credit" which provides the solar customers with a credit for the energy they actually produce. This is calculated by first grossing up their total energy production to recognize the line loss benefit. Then APS applied the EPR-6 excess generation rate (see APS15773 for a copy of the EPR-6 tariff) to the grossed up amount of energy produced to calculate the Energy Fuel Credit. This amount is then credited to the solar energy customers. The total amount credited for solar energy customers was $8M and for solar demand customers it was $370k. See APS15768.

- An explicit "Transmission Credit" was not developed in this study. However, transmission costs were allocated on a delivered energy basis. This is conservative and over-credits solar energy customers for avoided transmission. A more precise method would be to allocate cost at the 4 system coincident peak months and credit the difference based on the delivered data.

- A "Distribution Credit" was not applied since the non-coincident peak occurred at nearly the same time for both site and delivered data, thus indicating no significant avoided distribution costs.

No other avoided costs existed as a results of rooftop solar generation.

c. The credits are inputs into the working model, but attached as APS15768 are the workpapers that calculate each avoided cost mentioned above. The calculation is done as a separate analysis using load data and information from the cost of service and then the credits are applied in the O&M report in the cost of service, which reduces the overall cost to serve those customers.

ARIZONA PUBLIC SERVICE COMPANY
Solar Cost of Service Study
Production Energy Credit
Test Year Ending 12/31/2014

	Customer Class	MWhs @ Customer Level	MWhs @ Generation Level	EPR-6 Fuel Rate (cents/kWh)	2014 Solar Fuel Credit
1.	Residential - Solar Generation (Energy Rates)	258,473	278,731	2.895	$8,069,264
2.	Residential - Solar Generation (Demand Rates)	11,839	12,767	2.895	$369,612
3.	Total	270,312	291,498		$8,438,876

ARIZONA PUBLIC SERVICE COMPANY
Solar Cost of Service Study
Production Demand Credit
Test Year Ending 12/31/2014

	Customer Class	Coincident Peak (MW) Delivered	Coincident Peak (MW) Site	Class NCP [On-Peak] (MW) Delivered	Class NCP [On-Peak] (MW) Site
1.	Residential - Solar Generation (Energy Rates)				
	June	76.5	104.1	93.4	104.8
	July	94.9	122.5	111.3	122.5
	August	93.2	119.8	94.2	105.1
	September	60.0	103.8	99.2	107.1
	Average	81.2	112.6	99.5	109.9
	Relationship - Delivery versus Site		27.90%		9.42%
	Peak 2 Point Average				**18.66%**

	Customer Class	Coincident Peak (MW) Delivered	Coincident Peak (MW) Site	Class NCP [On-Peak] (MW) Delivered	Class NCP [On-Peak] (MW) Site
2.	Residential - Solar Generation (Demand Rates)				
	June	5.1	6.5	6.1	6.6
	July	6.2	7.5	7.1	7.5
	August	6.2	7.5	6.0	6.5
	September	4.0	6.3	6.2	6.6
	Average	5.4	7.0	6.4	6.8
	Relationship - Delivery versus Site		22.66%		6.62%
	Peak 2 Point Average				**14.64%**

Calculation of Demand Credit - Residential - Solar Generation (Energy Rates)

	Revenue Requirement @ -6.54% (Before Demand Credit)	**Targeted Revenue Requirement @ Avg Residential ROR 4.99%**
Total Rate Base	$51,435,445	$51,435,445
Return on Rate Base	($3,363,878)	$2,566,629
Taxes	($3,023,197)	$798,893
Expense	$10,277,250	$10,277,250
Revenue Credits	($1,598,373)	($1,598,373)
Revenue Requirement @ -6.54% (before Demand Credit)	$2,291,802	$12,044,399
% Difference in Delivery vs. Site		**18.66%**
Solar Demand Credit		**$2,247,395**

Residential - Solar Generation (Demand Rates)

	Revenue Requirement @ .79% (Before Demand Credit)	**Targeted Revenue Requirement @ Avg Residential ROR 4.99%**
Total Rate Base	$3,289,477	$3,289,477
Return on Rate Base	$25,987	$164,145
Taxes	($37,948)	$51,092
Expense	$651,121	$651,121
Revenue Credits	($119,754)	($119,754)
Revenue Requirement @ -6.54% (before Demand Credit)	$519,406	$746,604
% Difference in Delivery vs. Site		**14.64%**
Solar Demand Credit		**$109,301**

ARIZONA PUBLIC SERVICE
FUNCTIONALIZED REVENUE REQUIREMENT
TEST YEAR ENDING 12/31/2014

Residential Solar @ Actual ROR (Energy Rates - SITE) — Unbundled Functional Revenue Requirement

		Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
	Rate Base												
1)	Rate Base (excluding Cust. Advances & Deposits)	$51,451,369	$1,356,802		$6,216,972	$26,756,298	$20,811,249	$0	$4,840,752			$3,019,457	$114,452,899
2)	Customer Accounts							$1,794,234		$107,877	$121,842		$2,023,953
3)	Cust. Service & Info and Sales Expense							$580,497					$580,497
4)	Customer Deposits				($42,810)	($184,243)	($143,305)						(370,358)
5)	Customer Advances	($15,924)			($71,696)	($308,560)	($240,001)						($636,181)
6)	Total Rate Base	$51,435,445	$1,356,802	$0	$6,102,466	$26,263,495	$20,427,943	$2,374,731	$4,840,752	$107,877	$121,842	$3,019,457	$116,050,810
7)	Actual Earned ROR @ -6.54%												
8)	Return on Rate Base (Line 6 * Line 7)	($3,363,878)	($88,735)	$0	($399,101)	($1,717,633)	($1,335,987)	($155,307)	($316,585)	($7,055)	($7,968)	($197,472)	($7,589,723)
	Computation of Income Taxes												
9)	Weighted Cost of Long Term Debt @ 2.58%												
10)	Tax Rate @ 39.19%												
11)	Income Taxes ((Line 7-Line 9)(Line 6)(Line 10))/(1-Line 10)	($3,023,197)	($79,748)	$0	($358,682)	($1,543,677)	($1,200,684)	($139,578)	($284,523)	($6,341)	($7,161)	($177,473)	($6,821,064)
	Expenses												
12)	Expenses	$10,277,250	$9,637,630	$3,561,494	$567,284	$2,791,108	$2,038,147		$1,337,751			$1,208,737	$31,419,401
13)	Customer Accounts							$1,533,621		$304,642	$115,894		$1,954,157
14)	Cust. Service & Info and Sales Expense							$700,635					$700,635
15)	Total Expenses	$10,277,250	$9,637,630	$3,561,494	$567,284	$2,791,108	$2,038,147	$2,234,256	$1,337,751	$304,642	$115,894	$1,208,737	$34,074,193
	Revenue Requirement												
16)	Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$3,890,175	$9,469,147	$3,561,494	($190,499)	($470,202)	($498,524)	$1,939,370	$736,643	$291,246	$100,764	$833,791	$19,663,406
17)	Less: Revenue Credits	($1,598,373)	($2,733,994)	($847,066)	($35,400)	($201,831)	($125,584)	($9,763)	($22,010)	$0	$0	$0	($5,574,021)
18)	**REVENUE REQUIREMENT @-6.54%**	**$2,291,802**	**$6,735,153**	**$2,714,428**	**($225,899)**	**($672,033)**	**($624,108)**	**$1,929,607**	**$714,633**	**$291,246**	**$100,764**	**$833,791**	**$14,089,385**
19)	**Energy Consumption (MWh)**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**
20)	**Functional Unit Costs (cents/kWh)**	**0.0086**	**0.0252**	**0.0102**	**-0.0008**	**-0.0025**	**-0.0023**	**0.0072**	**0.0027**	**0.0011**	**0.0004**	**0.0031**	**0.0527**
21)	**Number of Customers**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**
22)	**Functional Unit Costs ($/Customer/month)**	**$7.05**	**$20.73**	**$8.35**	**-$0.70**	**-$2.07**	**-$1.92**	**$5.94**	**$2.20**	**$0.90**	**$0.31**	**$2.57**	**$43.36**

Residential Solar @ Targeted ROR (Energy Rates - SITE) — Unbundled Functional Revenue Requirement

		Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
	Rate Base												
1)	Rate Base (excluding Cust. Advances & Deposits)	$51,451,369	$1,356,802		$6,216,972	$26,756,298	$20,811,249		$4,840,752			$3,019,457	$114,452,899
2)	Customer Accounts							1,794,234		107,877	121,842		$2,023,953
3)	Cust. Service & Info and Sales Expense							$580,497					$580,497
4)	Customer Deposits				(42,810)	(184,243)	(143,305)						(370,358)
5)	Customer Advances	(15,924)			(71,696)	(308,560)	(240,001)						($636,181)
6)	Total Rate Base	$51,435,445	$1,356,802	$0	$6,102,466	$26,263,495	$20,427,943	$2,374,731	$4,840,752	$107,877	$121,842	$3,019,457	$116,050,810
7)	Targeted ROR @ 4.99%												
8)	Return on Rate Base (Line 6 * Line 7)	$2,566,629	$67,704	$0	$304,513	$1,310,548	$1,019,354	$118,499	$241,554	$5,383	$6,080	$150,671	$5,790,935
	Computation of Income Taxes												
9)	Weighted Cost of Long Term Debt @ 2.58%												
10)	Tax Rate @ 39.19%												
11)	Income Taxes ((Line 7-Line 9)(Line 6)(Line 10))/(1-Line 10)	$798,893	$21,074	$0	$94,783	$407,923	$317,286	$36,884	$75,186	$1,676	$1,892	$46,898	$1,802,496
	Expenses												
12)	Expenses	10,277,250	9,637,630	3,561,494	567,284	2,791,108	2,038,147		$1,337,751			$1,208,737	$31,419,401
13)	Customer Accounts							1,533,621		304,642	115,894		$1,954,157
14)	Cust. Service & Info and Sales Expense							$700,635					$700,635
15)	Total Expenses	$10,277,250	$9,637,630	$3,561,494	$567,284	$2,791,108	$2,038,147	$2,234,256	$1,337,751	$304,642	$115,894	$1,208,737	$34,074,193
	Revenue Requirement												
16)	Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$13,642,772	$9,726,408	$3,561,494	$966,580	$4,509,580	$3,374,787	$2,389,639	$1,654,491	$311,701	$123,866	$1,406,306	$41,667,625
17)	Less: Revenue Credits	($1,598,373)	($2,733,994)	($847,066)	($35,400)	($201,831)	($125,584)	($9,763)	($22,010)	$0	$0	$0	($5,574,021)
18)	**REVENUE REQUIREMENT @4.99%**	**$12,044,399**	**$6,992,414**	**$2,714,428**	**$931,180**	**$4,307,749**	**$3,249,203**	**$2,379,876**	**$1,632,481**	**$311,701**	**$123,866**	**$1,406,306**	**$36,093,604**
19)	**Energy Consumption (MWh)**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**	**267,212**
20)	**Functional Unit Costs (cents/kWh)**	**0.0451**	**0.0262**	**0.0102**	**0.0035**	**0.0161**	**0.0122**	**0.0089**	**0.0061**	**0.0012**	**0.0005**	**0.0053**	**0.1351**
21)	**Number of Customers**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**	**27,078**
22)	**Functional Unit Costs ($/Customer/month)**	**$37.07**	**$21.51**	**$8.35**	**$2.87**	**$13.26**	**$10.00**	**$7.32**	**$5.02**	**$0.96**	**$0.38**	**$4.33**	**$111.07**
23)	**Under Recovery (Targeted less Actual)($/Cust/Month)**	**$30.01**	**$0.78**	**$0.00**	**$3.56**	**$15.33**	**$11.92**	**$1.39**	**$2.82**	**$0.06**	**$0.07**	**$1.76**	**$67.71**

ARIZONA PUBLIC SERVICE
FUNCTIONALIZED REVENUE REQUIREMENT
TEST YEAR ENDING 12/31/2014

Residential Solar @ Actual ROR (Demand Rates - SITE) — **Unbundled Functional Revenue Requirement**

Line	Description	Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
	Rate Base												
1)	Rate Base (excluding Cust. Advances & Deposits)	$3,290,495	$93,321		$383,085	$1,648,723	$1,164,809	$0	$210,234			$207,678	$6,998,345
2)	Customer Accounts							$77,924		$4,685	$5,292		$87,901
3)	Cust. Service & Info and Sales Expense							$25,211					$25,211
4)	Customer Deposits				($5,961)	($25,655)	($18,125)						(49,741)
5)	Customer Advances	($1,018)			($9,983)	($42,966)	($30,355)						($84,322)
6)	Total Rate Base	$3,289,477	$93,321	$0	$367,141	$1,580,102	$1,116,329	$103,135	$210,234	$4,685	$5,292	$207,678	$6,977,394
7)	Actual Earned ROR @ 0.79%												
8)	Return on Rate Base (Line 6 * Line 7)	$25,987	$737	$0	$2,900	$12,483	$8,819	$815	$1,661	$37	$42	$1,641	$55,121
	Computation of Income Taxes												
9)	Weighted Cost of Long Term Debt @ 2.58%												
10)	Tax Rate @ 39.19%												
11)	Income Taxes ((Line 7-Line 9)(Line 6)(Line 10))/(1-Line 10)	($37,948)	($1,077)	$0	($4,235)	($18,228)	($12,878)	($1,190)	($2,425)	($54)	($61)	($2,396)	($80,493)
	Expenses												
12)	Expenses	$651,121	$876,242	$241,673	$41,673	$171,988	$113,594		$58,099			$83,137	$2,237,527
13)	Customer Accounts							$66,605		$13,231	$5,033		$84,869
14)	Cust. Service & Info and Sales Expense							$47,078					$47,078
15)	Total Expenses	$651,121	$876,242	$241,673	$41,673	$171,988	$113,594	$113,683	$58,099	$13,231	$5,033	$83,137	$2,369,474
	Revenue Requirement												
16)	Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$639,160	$875,903	$241,673	$40,338	$166,242	$109,535	$113,308	$57,335	$13,214	$5,014	$82,382	$2,344,103
17)	Less: Revenue Credits	($119,754)	($202,970)	($97,447)	$0	($2,181)	($12,437)	($7,030)	($3,655)	($956)	$0	$0	($446,430)
18)	**REVENUE REQUIREMENT @0.79%**	**$519,406**	**$672,933**	**$144,226**	**$40,338**	**$164,061**	**$97,098**	**$106,278**	**$53,680**	**$12,258**	**$5,014**	**$82,382**	**$1,897,673**
19)	**Energy Consumption (MWh)**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**
20)	**Functional Unit Costs (cents/kWh)**	**0.0264**	**0.0342**	**0.0073**	**0.0020**	**0.0083**	**0.0049**	**0.0054**	**0.0027**	**0.0006**	**0.0003**	**0.0042**	**0.0964**
21)	**Number of Customers**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**
22)	**Functional Unit Costs ($/Customer/month)**	**$36.81**	**$47.70**	**$10.22**	**$2.86**	**$11.63**	**$8.88**	**$7.53**	**$3.80**	**$0.87**	**$0.36**	**$5.84**	**$134.48**

Residential Solar @ Targeted ROR (Demand Rates - SITE) — **Unbundled Functional Revenue Requirement**

Line	Description	Production Demand	Production Energy	Transmission & Scheduling	Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)	Distribution (Customer Accounts, Cust. Service, Sales)	Metering	Billing	Meter Reading	System Benefits	Total
	Rate Base												
1)	Rate Base (excluding Cust. Advances & Deposits)	$3,290,495	$93,321		$383,085	$1,648,723	$1,164,809		$210,234			$207,678	$6,998,345
2)	Customer Accounts							77,924		4,685	5,292		$87,901
3)	Cust. Service & Info and Sales Expense							$25,211					$25,211
4)	Customer Deposits				(5,961)	(25,655)	(18,125)						(49,741)
5)	Customer Advances	(1,018)			(9,983)	(42,966)	(30,355)						($84,322)
6)	Total Rate Base	$3,289,477	$93,321	$0	$367,141	$1,580,102	$1,116,329	$103,135	$210,234	$4,685	$5,292	$207,678	$6,977,394
7)	Targeted ROR @ 4.99%												
8)	Return on Rate Base (Line 6 * Line 7)	$164,145	$4,657	$0	$18,320	$78,847	$55,705	$5,146	$10,491	$234	$264	$10,363	$348,172
	Computation of Income Taxes												
9)	Weighted Cost of Long Term Debt @ 2.58%												
10)	Tax Rate @ 39.19%												
11)	Income Taxes ((Line 7-Line 9)(Line 6)(Line 10))/(1-Line 10)	$51,092	$1,449	$0	$5,702	$24,542	$17,339	$1,602	$3,265	$73	$82	$3,226	$108,373
	Expenses												
12)	Expenses	651,121	876,242	241,673	41,673	171,988	113,594		$58,099			$83,137	$2,237,527
13)	Customer Accounts							66,605		13,231	5,033		$84,869
14)	Cust. Service & Info and Sales Expense							$47,078					$47,078
15)	Total Expenses	$651,121	$876,242	$241,673	$41,673	$171,988	$113,594	$113,683	$58,099	$13,231	$5,033	$83,137	$2,369,474
	Revenue Requirement												
16)	Return, Income Taxes, and Expenses (Line 8 + Line 11 + Line 15)	$866,358	$882,348	$241,673	$65,696	$275,377	$186,638	$120,431	$71,855	$13,538	$5,379	$96,726	$2,826,019
17)	Less: Revenue Credits	($119,754)	($202,970)	($97,447)	$0	($2,181)	($12,437)	($7,030)	($3,655)	($956)	$0	$0	($446,430)
18)	**REVENUE REQUIREMENT @4.99%**	**$746,604**	**$679,378**	**$144,226**	**$65,696**	**$273,196**	**$174,201**	**$113,401**	**$68,200**	**$12,582**	**$5,379**	**$96,726**	**$2,379,589**
19)	**Energy Consumption (MWh)**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**	**19,692**
20)	**Functional Unit Costs (cents/kWh)**	**0.0379**	**0.0345**	**0.0073**	**0.0033**	**0.0139**	**0.0088**	**0.0058**	**0.0035**	**0.0006**	**0.0003**	**0.0049**	**0.1208**
21)	**Number of Customers**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**	**1,176**
22)	**Functional Unit Costs ($/Customer/month)**	**$52.91**	**$48.13**	**$10.22**	**$4.66**	**$19.36**	**$12.34**	**$8.04**	**$4.83**	**$0.89**	**$0.38**	**$6.85**	**$166.61**
23)	**Under Recovery (Targeted less Actual)[$/Cust/Month]**	**$16.10**	**$0.44**	**$0.00**	**$1.80**	**$7.73**	**$5.46**	**$0.50**	**$1.03**	**$0.02**	**$0.03**	**$1.02**	**$34.13**

VOTE SOLAR'S SECOND SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER REGARDING THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET NO. E-00000J-14-0023
JANUARY 4, 2016

Vote Solar 2.4: Regarding APS's Response to VS 1.1:

Please provide the following information regarding VS 1.1_2014 COS Load Data_APS15747.xlsm.

a) Please describe the methodology APS used for the load data analysis.

b) Please indicate whether the load data shown for solar customers is the result of a statistical sampling of a subset of actual APS solar customers. If so, please describe the sampling methodology and indicate what proportion of APS solar customers were included in the sample. If not, please describe the derivation of the solar customer load data.

c) Please describe the meaning of the following terms as used in the titles of the spreadsheet tabs: "No Solar," "Solar Delivered," "Solar Site," "Solar Del," and "Solar Net."

Response:

a.) APS queries its energy data "warehouse" for all Residential AMI interval data. The AMI data is then sorted into the corresponding rates and categories (i.e. "No Solar", "Solar Delivered", "Solar Site", and "Solar Net"). A mean-per-unit analysis technique is then used to obtain the peak values for the report.

b.) APS's load data shown for solar customers is based on all solar customers' interval data.

c.) Term Definitions are as follows:

- *No Solar* – measured energy delivered from APS to customers who are not on a solar rate.
- *Solar Del / Solar Delivered* – measured energy delivered from APS to customers on a solar rate.
- *Solar Site* – the energy used by a customer based on the following formula: [Delivered Electricity + (Produced Electricity – Received Electricity)], where Delivered Electricity means energy delivered from APS to the customer and Received Electricity means energy delivered from the customer to APS.
- *Solar Net* – the energy used by a customer based on the following formula: [Delivered Electricity – Received Electricity].

Exhibit WAM-4: Excerpt from
"Effects of Home Energy Management Systems on Distribution Utilities and Feeders Under Various Market Structures," National Renewable Energy Laboratory, presented in the 23rd International Conference on Electricity Distribution, Lyon, France, June 15-18, 2015

Effects of Home Energy Management Systems on Distribution Utilities and Feeders under Various Market Structures

Preprint

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National Renewable Energy Laboratory

Presented at the 23rd International Conference on Electricity Distribution
Lyon, France
June 15–18, 2015

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

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Conference Paper
NREL/CP-6A20-63500
July 2015

Contract No. DE-AC36-08GO28308

controllers and custom reduced-order building models [10]. The model predictive controllers were also only run once per day, and a real-time price was provided as an input, based on historical CAISO prices and weather.

In this paper, we describe the IESM's structure. We then define the scenario used in the analysis; report results on the impact of HEMS technology on a feeder; and provide conclusions and propose future work.

INTEGRATED ENERGY SYSTEM MODEL

The Integrated Energy System Model (IESM) is being developed to analyze interactions between multiple technologies within various market and control structures, and to identify financial and physical impacts on both utilities and consumers. Physical impacts include both consumer comfort (e.g., difference between actual and desired temperature) and distribution feeder operations including voltage profiles and equipment loading. In addition, the IESM will be dynamically integrated into hardware in the loop (HIL) testing of technologies in the National Renewable Energy Laboratory's (NREL's) Energy Systems Integration Facility (ESIF) by providing market signals to technologies and equipment.

To meet these objectives, the IESM is being designed to perform simulations of a distribution feeder, end-use technologies deployed on it, and a retail market or tariff structure. The IESM uses co-simulation, wherein multiple simulators with specific modeling capabilities co-operate towards a common objective of bringing the capabilities together in a shared execution environment, and manages time and data exchange between component models. The co-simulation execution is performed on a high-performance computer (HPC).

In the current version, GridLAB-D, which performs distribution feeder, household, and market simulations, is co-simulated with Pyomo [11], which implements a HEMS for each household. GridLAB-D is an agent-based, open source power system simulation tool developed by the Pacific Northwest National Laboratory. It performs quasi-steady state simulations for distribution feeders, including end-use loads such as heating-cooling systems, water heaters and electric vehicles. It also manages retail markets and responses to market signals [8]. Similar to [10], the wholesale market is not included.

The IESM can include both price responsive thermostats, responding to the current price, and model predictive controllers which can be run several times during the day, which models the operation of such devices more realistically. In the reported case, the IESM utilizes HEMS, implemented in Pyomo, minimizes its house's cooling cost using a model predictive control approach and sets the cooling setpoint to a calculated optimal value while constrained by an envelope around the desired temperature [12]. No custom HVAC model was developed for the HEMS, instead, through the IESM's co-simulation structure, models available in existing software simulation packages are accessed.

Ultimately, the IESM will utilize an internal discrete event coordinator that operates on abstract time and an enterprise message bus as shown in Figure 1. The scheduler is expected to manage GridLAB-D's simulation of distribution feeders; actual or simulated loads and DER either in experimental hardware, GridLAB-D, or another simulation package such as Energy Plus [13]; and simulation of technologies, such as HEMS, markets, and consumers. Component libraries allow the creation of comprehensive scenarios, including different types of houses and market structures in a plug-and-play component-based manner.

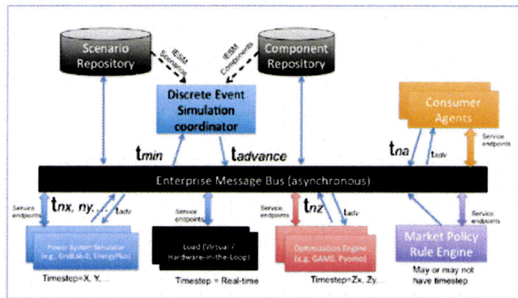

Figure 1. Integrated Energy System Model (IESM) architecture

SCENARIO DEFINITION

A scenario was created for a distribution feeder in the state of North Carolina in the Southeast of the United States in the summer for the month of July when air conditioning use is high. A distribution feeder based on the IEEE 13-node test feeder is used and about 3% of the load is replaced with houses in order to provide a price-responsive, varying load component [14].

The feeder is populated with 20 well-insulated houses with identical parameters, which are connected through four 25 kVA single-phase, center-tapped transformers – each serving 5 houses. The air conditioner in the house is modeled explicitly, and the rest of the household loads are modelled as a lumped ZIP load with a time-varying base power profile. The desired cooling temperature profile is motivated by EPA's Energy Star Recommendations [15]. The desired profile for each house is different, as shown in Figure 2. Each house has a desired daytime temperature between 72° and□77° F (22.2-25.0°C) that is set at uniformly distributed random time between 4:00 AM and 8:00 AM. The desired daytime temperature is constant for 16 hours and is set back by 3°F (1.7°C) at night for 8 hours. Each household's ZIP load base power profile has the same shift in time as the desired temperature.

Two retail electricity tariff structures that are currently in place for households in North Carolina are used. The first has a flat structure with a constant electricity price of $0.093587/kWh and a monthly service fee of $11.80 [16]. The TOU rate structure is shown in Figure 3. It has a varying electricity price with peak, shoulder, and off-peak rates and a monthly service fee of $14.13. The peak, shoulder, and off-peak rates are $0.2368/kWh,

$0.11961/kWh, and $0.06936/kWh, respectively. Summer peak hours are 1:00 PM to 6:00 PM, Monday through Friday and shoulder rates are in effect during the two hours before and after the peak hours [17]. All weekend hours are off-peak. Vertical shaded areas in this and other figures indicate peak and should pricing time periods.

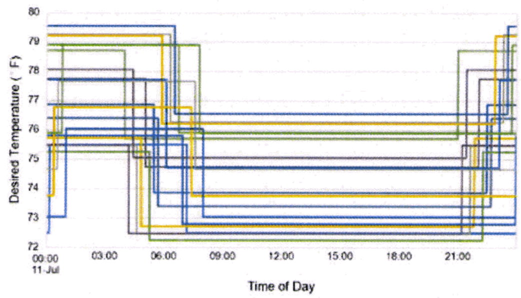

Figure 2. Desired temperature profile for each of the houses in the simulation. Daytime temperatures are randomly distributed between 72 and (22.2-25.0°C), set at a random time between 4:00 and 8:00 AM. After 16 hours, the desired temperature increases by 3°F (1.7°C).

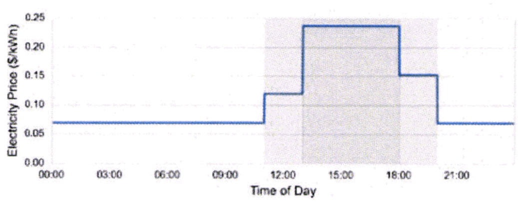

Figure 3. Time-of-use pricing profile for weekdays. All weekend hours are off-peak and have the lowest price

Three HEMS penetrations (0%, 50%, and 100%) are simulated to show how IESM can be used to evaluate the physical and financial impacts of distributed technologies, such as HEMS, in the presence of different markets or tariffs, on the system. Each house's HEMS uses model predictive control to adjust the cooling setpoint from the desired temperature to minimize cost. The HEMS does not allow the setpoint to be above the desired temperature, but does allow it to be down to 5°F (2.8°C) below the desired temperature so that the house can be precooled before peak electricity prices.

RESULTS

Figure 4 shows the range of electricity expenses for the households in the population. Those expenses vary because of variations in desired temperatures and their profiles between houses. For the time period analyzed, the uniform tariff has a lower cost than TOU due to high demand for cooling and other loads during peak hours. Presumably, that load will not be as large at other times of the year and bills under TOU tariffs will be lower during those seasons. Under TOU tariffs, bills are about 5% lower when HEMS are used to manage cooling.

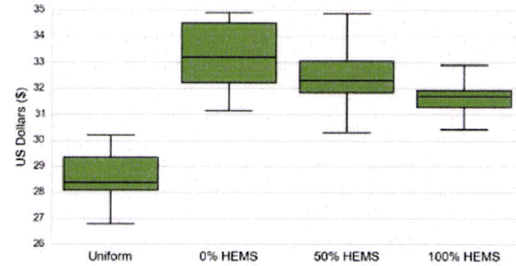

Figure 4. Box plot of the population's electricity bills over the time period from July 7-17, 2012. Use of HEMS reduces each household's bill by about 5%.

Cost savings are driven by the use of power during off-peak and shoulder times for precooling the houses. Figure 5 displays the total cooling power of all the houses over each day with vertically shaded bars indicating peak-price hours and shoulders. The solid lines display the mean total cooling loads over all 11 days, and the shaded areas indicates a 95% confidence interval. Results for the uniform price distribution are identical to the scenario with 0% HEMS penetrations.

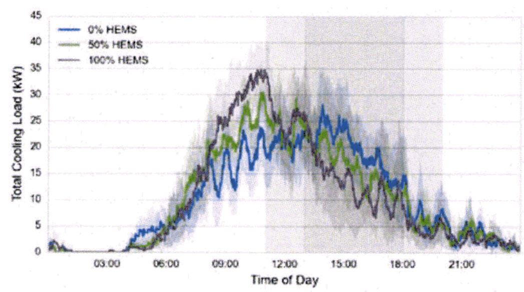

Figure 5. Daily profile of total cooling power load at several levels of HEMS penetrations. When HEMS are present, power use is shifted from peak hours to earlier times when it is less expensive.

When HEMS are present, power use is shifted from times when cost is higher (peak-price periods from 1:00 PM to 6:00 PM) to earlier hours when it is not as expensive. In addition, with the HEMS penetration levels simulated here, the peak is higher during the time period before prices increase than at any time without HEMS. The HEMS used in this study does not adjust any other household loads so they are not shifted due to pricing.

Figure 6 shows the total load on the distribution transformers. The solid line shows the mean and the shaded area shows a 95% confidence interval. The peak load during peak pricing is reduced with the HEMS penetration levels simulated here, but a new, higher peak load is created during the time period before peak pricing. Because the peak load is just shifted, the distribution feeder still experiences peak stress even though the TOU rate structure was likely designed to reduce the peak load.

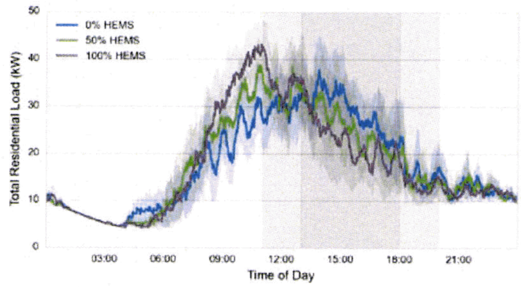

Figure 6. Daily profile of the total distribution transformer load with several HEMS penetrations. Presence of HEMS reduces the peak load during peak pricing but creates a new peak load in the time period before peak pricing is in effect.

Using power to precool intrinsically indicates that the house's temperature setpoint is lower than desired for a time before the peak pricing period. Figure 7 shows the daily profile of the population's average temperature over all days with and without HEMS. The solid line shows the mean and the shaded area shows a 95% confidence interval. The average of the population with HEMS precools by almost 2°F (1.2°C) as compared to the population without HEMS (i.e., without cost optimization). Note that the starting time for cooling is consistent because the two populations have the same time for the initial house's change in desired temperature and, during that time, the setpoint for both is the desired temperature.

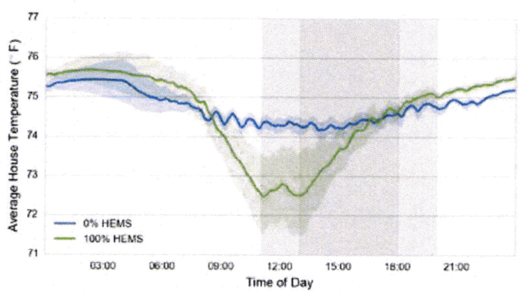

Figure 7. Daily profile of mean household temperature for the population with and without HEMS. HEMS minimize cost by precooling by about 2°F (1.1°C) before peak pricing is in place.

Figure 8 shows the daily profile of the primary voltage of the distribution transformer at node 652. It serves five houses. The solid lines display the mean and the shaded area indicates a 95% confidence interval. With HEMS, the lowest voltage is experienced at an earlier time in the day, coinciding with the peak transformer load moving earlier due to precooling. The minimum voltage is lower in this case, due to the fact that the peak transformer load is higher with HEMS than without. Overall the voltage variation is small due to the fact that only a small percentage of the load at this node is replaced with houses that provide a time-varying load component.

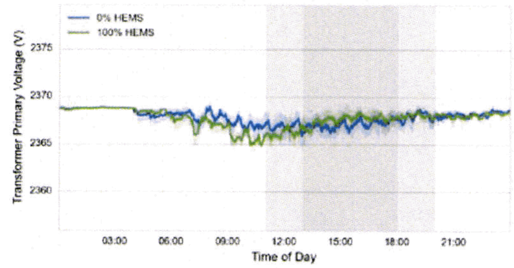

Figure 8. Daily profile of primary voltage of the transformer at node 652 and serving five houses. Use of HEMS shifts time of low voltage to coincide with new peak introduced by HEMS.

Utility net revenue is calculated as the difference between income from the household electricity bills reported above and the wholesale cost of the electricity provided. The wholesale cost of the electricity is calculated as the product of the total electricity demand for the feeder and the Midcontinent Independent Service Operations hourly real-time locational marginal prices for a hub in North Carolina (price node 746136) and are assumed to be unaffected by the modelled changes in the load.

Table 1: Comparison of household expenditures and utility net revenue between scenarios

	Sum of household expenditures	Utility net revenue
Uniform rate	$573	$470
TOU rate – 0% HEMS	$665	$562
TOU rate – 50% HEMS	$650	$547
TOU rate – 100% HEMS	$632	$530

Table 1 shows the utility net revenue and the total household expenditure for the four scenarios. Utilizing HEMS reduces the sum of household expenditures by $33 in the time period analyzed, but only reduces the utility net revenue by $32. Where bulk power prices are unaffected by load, utility net revenue is reduced by approximately the same amount as household expenditure reductions; thus, indicating that the TOU rate structure provides similar net revenue at all times.

CONCLUSIONS AND FUTURE WORK

This paper presented results from a specific scenario simulated using a co-simulation platform, the Integrated Energy System Model (IESM), under development to study the physical and economic impact of distributed technologies under different markets or tariff structures.

The results reported here show that the combination of time-of-use (TOU) pricing and Home Energy Management Systems (HEMS) controlling residential cooling systems reduces peak load during high price hours but moves the load peak to hours with off-peak and shoulder prices. This situation would be further exacerbated with HEMS that are able to shift the operation of multiple loads within a household in

Exhibit WAM-5: Excerpt from

"Energy Star: Program Requirements for Programmable Thermostats,"

ENERGY STAR® Program Requirements for Programmable Thermostats

Partner Commitments
DRAFT 1

Commitment

The following are the terms of the ENERGY STAR Partnership Agreement as it pertains to the manufacturing of ENERGY STAR qualified programmable thermostats. The ENERGY STAR Partner must adhere to the following program requirements:

- comply with current ENERGY STAR Eligibility Criteria, defining the performance criteria that must be met for use of the ENERGY STAR certification mark on programmable thermostats and specifying the testing criteria for programmable thermostats. EPA may, at its discretion, conduct tests on products that are referred to as ENERGY STAR qualified. These products may be obtained on the open market, or voluntarily supplied by Partner at EPA's request;

- comply with current ENERGY STAR Identity Guidelines, describing how the ENERGY STAR marks and name may be used. Partner is responsible for adhering to these guidelines and for ensuring that its authorized representatives, such as advertising agencies, dealers, and distributors, are also in compliance;

- qualify at least one ENERGY STAR qualified programmable thermostat model within one year of activating the programmable thermostat portion of the agreement. When Partner qualifies the product, it must meet the specification (e.g., Tier 1 or 2) in effect at that time;

- provide clear and consistent labeling of ENERGY STAR qualified programmable thermostats. The ENERGY STAR mark must be clearly displayed on the front/inside of the product, on the product packaging, in product literature (i.e., user manuals, spec sheets, etc.), and on the manufacturer's Internet site where information about ENERGY STAR qualified models is displayed;

> **Note:** EPA requires the labeling of all ENERGY STAR qualified products according to one or more of the following options, depending on product design and visibility at both the time of sale and over the use of the product: on the product; in product literature; and on the manufacturer's Internet site. The ENERGY STAR mark is well known by consumers and large purchasers as the symbol for energy efficiency. The ENERGY STAR mark should be placed in an area of high visibility, preferably on front of the product, so that the purchaser and end users can see that by purchasing and using an ENERGY STAR qualified programmable thermostat, they are helping to reduce air pollution and greenhouse gases through energy efficiency. EPA is open to discussing additional placement options.

- provide to EPA, on an annual basis, an updated list of ENERGY STAR qualifying programmable thermostat models. Once the Partner submits its first list of ENERGY STAR qualified programmable thermostat models, the Partner will be listed as an ENERGY STAR Partner. Partner must provide annual updates in order to remain on the list of participating product manufacturers;

- provide to EPA, on an annual basis, unit shipment data or other market indicators to assist in determining the market penetration of ENERGY STAR. Specifically, Partner must submit the total number of ENERGY STAR qualified programmable thermostats shipped (in units by model) or an

1. **Default Program**. The setbacks and setups periods are required to be a **minimum of** 8 hours, but may exceed 8 hours. Partners must have four events on the weekday and two on the weekend, partners may choose to add additional setbacks and/or setups as long as the setback/setup period is at least eight-hours long. Listed below are the suggested events along with setbacks/setups and appropriate temperatures (Tables 1-3).

Table 1: Programmable Thermostat Setpoint Temperatures

Events	Setpoint Temperature (Heat)	Setpoint Temperature (Cool)
Morning	≤70°F (≤21.1°C)	≥75°F (≤25.6°C)
Day	setback at least 8°F (4.4°C)	setup at least 8°F (3.8°C)
Evening	≤70°F (≤21.1°C)	≥75°F (≤25.6°C)
Night	setback at least 8°F (4.4°C)	setup at least 3°F (2.2°C)

Table 2: Acceptable Weekday Setpoint Times and Temperature Settings

Events	Time	Setpoint Temperature (Heat)	Setpoint Temperature (Cool)
Morning	6 a.m.	≤70°F (≤21.1°C)	≥75°F (≤23.9°C)
Day	8 a.m.	≤62°F (≤16.71°C)	≥83°F (≤29.4°C)
Evening	6 p.m.	≤70°F (≤21.1°C)	≥75°F (≤23.9°C)
Night	10 p.m.	≤62°F (≤16.71°C)	≥78°F (≤25.6°C)

Table 3: Acceptable Weekend Setpoint Times and Temperature Settings

Events	Time	Setpoint Temperature (Heat)	Setpoint Temperature (Cool)
Morning	8 a.m.	≤70°F (≤21.1°C)	≥75°F (≤23.9°C)
Day	10 a.m.	≤62°F (≤16.71°C)	≥83°F (≤29.4°C)
Evening	6 p.m.	≤70°F (≤21.1°C)	≥75°F (≤23.9°C)
Night	11 p.m.	≤62°F (≤16.71°C)	≥78°F (≤25.6°C)

Exhibit WAM-6: Excerpt from

Qinran Hu, and Fangxing Li. "Hardware Design of Smart Home Energy Management System With Dynamic Price Response." IEEE Transactions on Smart Grid 4, no. 4 (December 2013)

Hardware Design of Smart Home Energy Management System With Dynamic Price Response

Qinran Hu, *Student Member, IEEE*, and Fangxing Li, *Senior Member, IEEE*

***Abstract*—The smart grid initiative and electricity market operation drive the development known as demand-side management or controllable load. Home energy management has received increasing interest due to the significant amount of loads in the residential sector. This paper presents a hardware design of smart home energy management system (SHEMS) with the applications of communication, sensing technology, and machine learning algorithm. With the proposed design, consumers can easily achieve a real-time, price-responsive control strategy for residential home loads such as electrical water heater (EWH), heating, ventilation, and air conditioning (HVAC), electrical vehicle (EV), dishwasher, washing machine, and dryer. Also, consumers may interact with suppliers or load serving entities (LSEs) to facilitate the load management at the supplier side. Further, SHEMS is designed with sensors to detect human activities and then a machine learning algorithm is applied to intelligently help consumers reduce total payment on electricity without or with little consumer involvement. Finally, simulation and experiment results are presented based on an actual SHEMS prototype to verify the hardware system.**

***Index Terms*—Controllable load, demand response, dynamic pricing, embedded system, machine learning, optimal control strategies, peak shaving, remote operation, smart home energy management system (SHEMS).**

NOMENCLATURE

F_i	Signals from sensors.
C	User's activity.
$X_T(t)$	Temperature in electrical water heater at time t, °C.
$X_a(t)$	Ambient temperature at time t, °C.
a	Thermal resistance of tank walls, W/°C.
$A(t)$	Rate of energy extraction when water is in demand at time t.
$q(t)$	Status of the hot water demand at time t, ON/OFF.
P_{EWH}	Power rating of the heating element, W.
P_{EV}	Power rating of charging station, W.
P_H	Power rating of dishwasher, washing machine, or dryer, W.
$m(t)$	Thermostat binary state at time t, ON/OFF.
$RTP(t)$	Real time price at time t, $/MWh.
$S_{EV}(t)$	Status of charging station, ON/OFF.
TF_{EV}	The time EV needs to get fully charged (hour).
R_{EV}	Desired percentage of battery being charged.
T_{start}	The time when EV is connected to charging station.
T_{end}	The time when the user needs to drive EV.
T_{hstart}	The time when dishwasher, washing machine, or dryer starts to work.
T_{huse}	Time duration for dishwasher, washing machine, and dryer to complete the work once started.
T_{hready}	The time when dishwasher, washing machine, and dryer is ready to use.
T_{hend}	The time when the user needs to pick up things from the dishwasher, the washing machine or the dryer.

Manuscript received October 14, 2012; revised February 26, 2013 and April 04, 2013; accepted April 04, 2013. Date of publication June 06, 2013; date of current version November 25, 2013. This work was supported by the NSF under Grant ECCS 1001999. Also, this work made use of Engineering Research Center (ERC) Shared Facilities supported by the CURENT Industry Partnership Program and the CURENT Industry Partnership Program. Paper no. TSG-00720-2012.

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Color versions of one or more of the figures in this paper are available online at http://ieeexplore.ieee.org.

Digital Object Identifier 10.1109/TSG.2013.2258181

I. INTRODUCTION

THE electricity prices in a competitive power market are closely related to the consumers' demand. However, the lack of real-time pricing (RTP) technologies presents challenges to electricity market operators to optimally signal and respond to scarcity, because electricity cannot be stored economically [1]. In the past a few years, the deployment of advanced metering infrastructures (AMI) and communication technologies make RTP technically feasible [2]. RTP, generally speaking, reflects the present supply-demand ratio and provides a means for load-serving entities (LSEs) and independent system operators (ISOs) to solve issues related to demand side management such as peak-load shaving. Applications of RTP enable consumers and suppliers to interact with each other, which also creates an opportunity for consumers to play an increasingly active role in the present electricity market with optimal control strategies at the demand side.

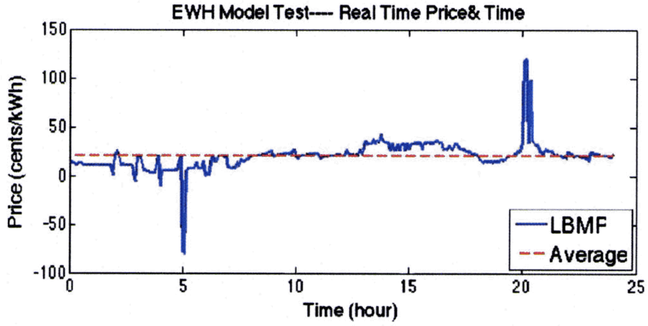


Fig. 11. Real time price curve for 24 hours.

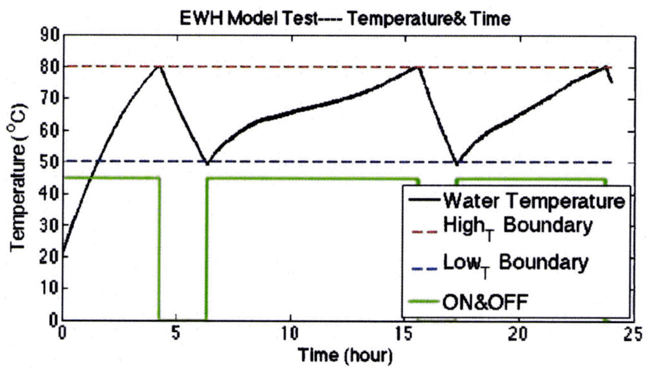


Fig. 12. Typical EWH strategy [26].

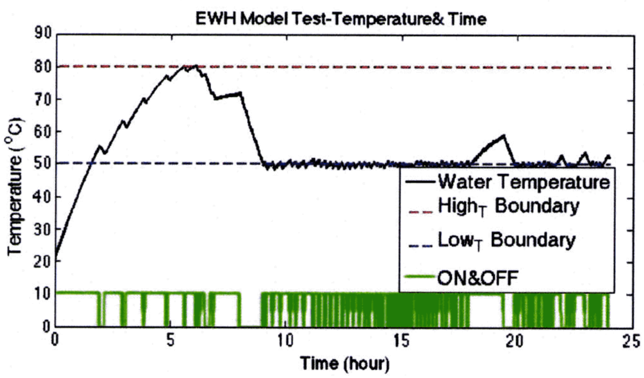


Fig. 13. Optimized EWH strategy.

signal may change as fast as every 5 minutes which is a discrete variable. The model can be described by:

$$\frac{dX_T}{dt} = -a\left(X_T(t) - X_a(t)\right) - A(t)q(t) + P_{EWH} \cdot m(t) \quad (2)$$

Table II shows the specifications of EWH used in the experiment. For testing and simulation purposes, Table III shows some useful information applied here. Also, a typical water usage curve as shown in Fig. 10 is obtained from [25].

In this study, the locational marginal price (LMP) on a randomly selected day from NYISO is used as the real-time price, which is shown in Fig. 11. The result without SHEMS is shown in Fig. 12, and the results after applying an RTP-responsive algorithm to change the ON and OFF strategy of EWH is shown in Fig. 13.

The optimized strategy used in the test can be further improved in future algorithm/software studies, while this paper focuses on the hardware part. Nevertheless, the straightforward algorithm still works greatly. A brief description of the algorithm is presented next.

The principle of the algorithm is to turn EWH on for a while before the dropping temperature reaches the lower bound. Meanwhile, the algorithm also considers whether the EWH can provide comfortable hot water based on the predicted consumer demand of water usage with a look-ahead consideration. For example, the algorithm will preheat the EWH to a higher temperature before the consumer takes a shower. The mathematical description is an optimization model given below.

$$\min \int_0^{24} RTP(t) \cdot m(t) \cdot P_{EWH} \quad (3)$$

$$\text{s.t.}: \quad \text{Eq. (2)}$$

$$T_{low} \le X_T(t) \le T_{high} \quad (4)$$

Since $RTP(t)$ refreshes every 5 minutes, this model given by (2), (3), and (4) is discretized into a time interval of 5 minutes. The genetic algorithm (GA), an intelligent search algorithm using stochastic operations, is customized in this work to solve the model to find the global optimal scheduling for the EWH. With this approach, SHMES can reduce the total payment and energy consumption while meeting the consumer's needs.

The result verifies that SHEMS helps reduce the thermostat ON time by 14%, while reducing the consumer's payment by 60% of the original payment on heating water.

The proposed SHEMS system has been programmed and tested to connect and disconnect a mock EWH load in accordance with Fig. 13.

B. Heating, Ventilation, and Air Conditioning (HVAC)

The American Society of Heating, Refrigeration and Air Conditioning Engineers, Inc. (ASHRAE) has compiled modeling procedures in its Fundamentals Handbook [27]. The Department of Energy has produced the Energy Plus program for computer simulation [28]. Also, the detailed model for simulating HVAC systems is given in [29], [30]. Accurate model for energy consumption needs to consider many factors including weather, season, thermal resistance of rooms, solar heating, cooling effect of the wind, and shading. Unlike EWH which has constant and relatively accurate parameters, those HVAC parameters are difficult to be precisely modeled with the possibility to change over the time due to other factors.

Thus, the testing here is not based on any detailed model but relies on the actual measurement from the experiments performed at the University of Tennessee with the SHEMS prototype and a portable HVAC unit.

In this experiment, the SHEMS optimizes the HVAC based on three parameters: the mock RTP from the prices in a randomly selected day in NYISO used in the previous EWH test, the real-time temperature in the test room, and the temperature setting by the user. Table IV shows the related parameters.

For comparison purpose, a parameter named "Comfort Level" is considered here. In market economics, a consumer has to compromise between quality and price. The introduction of "Comfort Level" is based on similar idea for home energy management. Simply speaking, "Comfort Level" in this case

TABLE IV
HVAC PARAMETERS IN THE TEST

Room Area	800 sq ft
Room Type	Single room
HVAC Power Rate	3.5kW
Room Temperature Setting	73°F (23°C)

TABLE V
HVAC RESULTS WITH SHEMS

	Different Comfort Level		
	+/- 0°C	+/- 3°C (5.8°F)	+/- 5°C (9°F)
Energy Consumption (% w.r.t the case w/o SHEMS)	91%	79%	72%
Payment (% w.r.t the case w/o SHEMS)	86%	73%	64%

means the difference between the actual indoor temperature and the temperature desired by the consumer.

Table V shows the energy consumption and the total payment reduction of the cases under different comfort levels with SHEMS. The results are in percentage with respect to the case without SHEMS. As shown in the table, considerable reduction of energy consumption and payment is achieved. Further, if a consumer can tolerate a higher temperature difference, more payment or credit to HVAC from the supplier can be achieved. This is sensible from the standpoint of market economics.

C. EV, Dishwasher, Washing Machine and Dryer

In order to fully exploit the potential of SHEMS and contribution to the power grid, low cost is an important characteristic of the prototype. Since considering bidirectional power flow will significantly increase the total cost of SHEMS design, the electric vehicle (EV) model in the proposed prototype is to charge a battery. That is, this design of SHEMS does not include the consideration for EV to send power back to grid.

Loads such as charging the battery for an EV are interruptible [15]. It is possible to charge the battery for 1 h, then stop charging for another hour, and then finish the charging after that. In contrast, the loads like dishwasher, washing machine and dryer demonstrate similar features to EV, but differ from EV considerably because they are uninterruptible. That is, as soon as the corresponding appliance starts operation, its operation should continue till completion.

1) Electrical Vehicles: An EV should be fully charged, for example, at 8 A.M. but the EV user does not care when or how the EV battery is charged. Therefore, SHEMS chooses the possible hours with the low electricity price to charge. Meanwhile, SHEMS must make sure EV to be fully charged before being used at 8 A.M..

As an interruptible load, the mathematical expression of the discrete model of EV can be expressed in (5) and (6). Since the real-time price refreshes every 5 minutes, the time interval of discrete model is also set to 5 minutes. Here, $S_{EV}(t)$ is the optimal solution that needs to be generated by SHEMS.

TABLE VI
PARAMETERS OF DISHWASHER, WASHING MACHINE, AND DRYER

	Model	P_H (W)	T_{huse} (min)
Dishwasher	Danby	1000	30
Washing machine	Danby	400	45
Dryer	Whirlpool	3000	40

$$\min \sum_{t=T_{start}}^{T_{end}} P_{EV} \cdot RTP(t) \cdot S_{EV}(t) \tag{5}$$

$$\text{s.t.}: \frac{1}{12} \cdot \sum_{t=T_{start}}^{T_{end}} S_{EV}(t) = TF_{EV} R_{EV} \tag{6}$$

2) Dishwasher, Washing Machine, and Dryer: As an uninterruptible load, the mathematical expression of the discrete model of dishwasher, washing machine and dryer can be all expressed in (7), (8), and (9), respectively. The time interval of discrete model is also set to 5 minutes. T_{hstart} is the optimal solution which needs to be generated by SHEMS.

$$\min \sum_{t=T_{hstart}}^{T_{hstart}+T_{huse}} P_H \cdot RTP(t) \tag{7}$$

$$\text{s.t.}: T_{hready} \le T_{hstart} \le T_{hend} \tag{8}$$

$$T_{hready} \le (T_{hstart} + T_{huse}) \le T_{hend} \tag{9}$$

D. Effects of SHEMS in Load Shifting

Based on the previous analysis on EWH and HVAC, it is rational to conclude that SHEMS can make substantial contribution to reduce home energy consumption from not only EWH and HVAC but also EV, dishwasher, washing machine, dryer, etc. To study the effect of SHEMS in a large-scale system, this section demonstrates a comparison on the load curves with and without SHEMS.

The simulation here is to give a quantified verification that SHEMS will play a critical role in load shifting. The total real-time load curve (including residential, commercial, industrial and other) is selected from NYISO again. The date of the data is the same as the date of the selected RTP.

The EWH and HVAC parameters are the same as from the previous Sections V-B and V-C. The EV parameters are chosen based on Nissan Leaf [31] for this simulation study:

- Charging power rate: approx. 6 kW;
- Battery volume: 24 kWh;
- Time of fully charging: 4 hour; and
- The percentage of EV battery to be charged is set as 100%.

The parameters of dishwasher, washing machine, and dryer are shown in Table VI.

The reduction of energy consumption from individual appliance is scaled up to simulate the optimized residential load consumption. The results are shown in Fig. 14, which illustrates that SHEMS can help with load shifting. In addition, it reduces the loads in peak hours by nearly 10 percent which is significant.

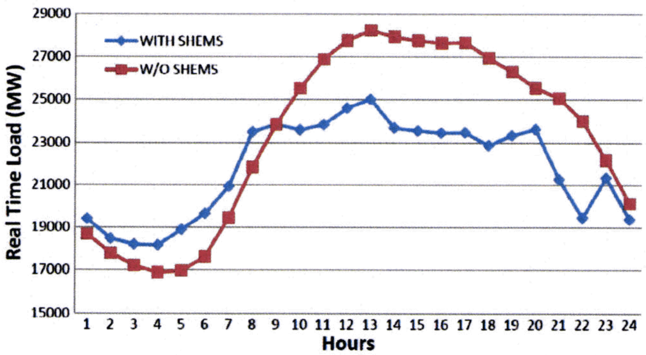


Fig. 14. Load curve comparison with and without SHEMS.

VI. Comparative Analysis and Conclusion

A. Comparative Analysis

As mentioned in the Introduction, there are several companies working on products related to demand response. However, those early products do not take full considerations of all aspects mentioned in this paper. Most of these previous products focus on displaying and monitoring the status of home energy consumption. Some advanced ones may help analyze power usages of different appliances, then offer tips for conserving energy and reducing payment in electricity, which is represented by the "Indirect Feedback" [32], [33]. None of those previous works has reported any real intelligent control down to the appliance level, and users' interaction is needed. However, the proposed design and the actual prototype carried out in our Smart Home lab implements automated, intelligent controls for smart home energy management to the appliance level.

As for the cost, the proposed design typically costs less than \$200 with off-the-shelf retail prices for materials and components. The actual cost also depends on the number of appliances that consumers want to install load interfaces, as well as the number of rooms to be monitored. Here is the cost breakdown in a typical case. The main controller costs around \$80 based on to the off-the-shelf retail price(\$15 for a microcontroller, \$20 for making PCB and accessories, \$15 Wi-Fi module, and \$30 for touch screen). Each load interface and room monitoring unit costs around \$20 (\$15 for Wi-Fi module and \$5 for accessories). With the assumption that a consumer wants to control HVAC and EWH, and has 3$\sim$4 rooms to monitor, the total cost will be around \$200 in this typical setting. In addition, this design is expandable and can be easily upgraded by updating programs running in the processor without any change of existing hardware.

Table VII provides a high-level comparison of the proposed design and 4 SHEMS-like devices from commercial vendors. These 4 devices include Monitor12 by Powerhouse, Home monition and Control by Verizon, Nucleus by GE, and Thermostat controller by NEST. The listed features are monitoring, remote control, real-time price responsive, machine learning, and easy setting. They are randomly named Vendor 1 to 4 without any particular order in Table VII. One of the vendor's cost is the annual service cost, while the device is sold separately. The cost of the system from Vendor 1 is relatively low, but with relatively simple functions. It does not have machine learning algorithm and cannot provide optimized schedule for home appliances. Vendor 4 provides a fancy user interface which is easy and efficient, but cannot control appliances other than HVAC.

TABLE VII
Comparison of Existing SHEMS

Name	Appliances	Monitor /Control	Response	Learn	Easy Setting	Cost (\$)
Proposed Design	Extendable	X	X	X	X	~200
Vendor 1	Vendor's own devices	X	X			199
Vendor 2	12 switches	X				1024
Vendor 3	Extendable	X				120/yr
Vendor 4	Thermostat	X		X	X	250

Note that the cost of the developed prototype may not be directly comparable with the costs of the four vendors' products since the cost of the developed prototype does not include labor cost and the expected profit. However, on the other hand, the prototype cost is based on retail prices of various materials and components, which are usually higher than wholesale prices under mass production. Nevertheless, the cost information is listed in Table VII for future references.

B. Conclusion

This paper presents a hardware design of a smart home energy management system (SHEMS) with the application of communication, sensing technology, and machine learning algorithm. With the proposed design, consumers can achieve a RTP-responsive control strategy over residential loads including EWHs, HVAC units, EVs, dishwashers, washing machines, and dryers. Also, they may interact with suppliers or load serving entities (LSEs) to facilitate the management at the supplier side. Further, SHEMS is designed with sensors to detect human activities and then apply machine learning algorithm to intelligently help consumers reduce total electricity payment without much involvement of consumers. In order to verify the effort, this paper also includes testing and simulation results which show the validity of the hardware system of the SHEMS prototype. The expandable hardware design makes SHEMS fit to houses regardless of its size or number of appliances. The only modules to extend are the sensors and load interfaces.

Also, if this design can be widely used in the future, the administrator-user structure will provide good potentials for electricity aggregators. Most likely, utilities may not be interested or motivated to administrate all individual, millions of end consumers directly and simultaneously. Therefore, electricity aggregators can play as agents between consumers and utilities. This business mode may facilitate the popularity of SHEMS or similar systems and create win-win results for all players.

Acknowledgment

The authors would like to thank NSF for financial support under Grant ECCS 1001999 to complete this research work. Also, this work made use of Engineering Research Center (ERC) Shared Facilities supported by the CURENT Industry Partnership Program and the CURENT Industry Partnership Program.

Exhibit WAM-7: Excerpt from

California Energy Markets, Issue No. 1379, April 1, 2016

AN INDEPENDENT NEWS SERVICE FROM ENERGY NEWSDATA

CALIFORNIA ENERGY MARKETS

◆ Friday, April 1, 2016 ◆ No. 1379 ◆

BILLBOARD No. 1379

Western Price Survey

[1] CARB Sets Sights on Including International Offsets in Cap and Trade

The California Air Resources Board is considering whether to allow programs aimed at reducing GHG emissions from tropical deforestation to count as offset credits in the state's cap-and-trade program. Initiatives that prevent deforestation are a critical part of addressing global climate change, and may even provide for direct environmental benefits within California, according to CARB. Energy companies are advocating for additional sources of offsets, saying they are needed for cost containment. ***Sinking carbon at [13].***

Photo: Crustmania, Flickr.com

[2] Cal-ISO: Resources Adequate to Meet Summer Loads

Cal-ISO expects to have adequate resources to meet summer demand. Peak demand should be up slightly in 2016, based on projected economic growth and new behind-the-meter solar installations, while hydroelectric capacity is projected to be near normal for both spring and summer. Cal-ISO did warn, however, of possible natural gas curtailments related to the Aliso Canyon natural gas storage facility. Meanwhile, the growth of rooftop solar helped cancel transmission upgrades planned for the Pacific Gas & Electric service area. ***At [14], generation and transmission.***

[3] CEC to Allow More Time for Puente Review

NRG Energy calls its Puente Power Project, a 262 MW natural gas plant proposed on the Southern California coast at Oxnard, "a bridge to California's energy future." Project opponents this week called for the California Energy Commission to allow more time to evaluate and comment on its environmental review of that "bridge." ***At [11], the CEC says it plans to revise its proposed schedule for Puente.***

[4] Davis, Yolo County to Form JPA for Launch of CCA Program

The City of Davis and Yolo County have agreed to form a joint-powers authority that will administer a community choice aggregation program, with the launch of service expected in 2017. The CCA would serve electricity customers in Davis and unincorporated areas of the county, in competition with incumbent utility Pacific Gas & Electric. The door is open for other cities in Yolo County to join in the aggregation effort down the road. ***At [15], stronger together?***

[14.1] Cal-ISO Board Approves Annual Transmission Plan

Thirteen new transmission projects with an estimated $288 million-dollar price tag were approved for construction by the Cal-ISO Board of Governors to ensure continued grid reliability.

According to the ISO's 2015-2016 Transmission Plan, each of the 13 projects costs less than $50 million and two-thirds are high-voltage upgrades needed to address reliability. None of the projects planned are policy- or economically-driven, which means there will be no need to take projects out for competitive bids, according to Cal-ISO, which approved the plan at its March 25 board meeting.

The transmission plan also called for canceling 13 sub-transmission projects in the Pacific Gas & Electric service area valued at $192 million. Some of these projects were originally approved in 2005. Of these, only two needed board approval—the Monta Vista-Wolfe and Newark-Applied Materials substation upgrades. Both 115 kV substation-upgrade projects were valued at $1 million each. However, Neil Millar, executive director of infrastructure development for Cal-ISO, said it is valuable "to get these cleared out of the way to focus on other projects going forward."

'We really appreciate the reappraisal of those projects.'

In his remarks to the board, Eric Eisenman, director of ISO relations and FERC policy for PG&E, conveyed the utility's support for the plan, including the project cancellations.

"The need for those is just not there anymore," he said. "We really appreciate the reappraisal of those projects." Load forecast has flattened in the service area from a combination of energy efficiency and rooftop solar, which eliminates the need for these upgrades, Eisenman said.

The utility plans to work with Cal-ISO on planning to prevent overbuilding and to ensure customers have affordable services. Future surveys, Eisenman said, would need to consider resources in the Oakland-East Bay area, which has an aging generation plant that may go off line. Roughly two-thirds of PG&E's $1 billion transmission budget is used to address maintenance and replacement of aging infrastructure.

This year's Cal-ISO transmission plan is "light" compared to previous plans, noted Steve Berberich, the grid operator's president and CEO, in his comments to the board. The 2012-2013 and 2013-2014 transmission plans were project-heavy to address issues in the PG&E service area and reliability requirements created by the early retirement of Units 2 and 3 of the San Onofre Nuclear Generating Station.

Among the new reliability projects identified in the 2015-2016 transmission plan are seven different projects, at a projected cost of $202 million, in the PG&E service area, including the reconductoring of the Panoche-Ora Loma 115 kV line and the Wilson 115 kV static VAR compensator (SVC) project.

Five projects are in the San Diego Gas & Electric service area and one is in the Southern California Edison service area. There are no projects planned in the Valley Electric Association service area in this planning cycle.

None of the transmission projects address the 2020 or 2030 renewables portfolio standards; however, Millar says there is a pressing need to better manage generation from renewable sources, which creates wider changes in operating conditions. Ultimately, this will require more voltage support across the system. The system operator is seeing "the impacts in real time" and needs to address these and other voltage-control issues, Millar said.

An upgrade to the Lugo-Victorville 500 kV line is needed, Millar and Berberich said, but Cal-ISO is coordinating with the Los Angeles Department of Water & Power on the project. A detailed cost-benefits analysis is needed because it is an interregional project, which pushes it into the 2016-2017 planning cycle. The needs of the Los Angeles Basin and San Diego areas specific to 230 kV loading in the region will also be addressed in that time frame.

Striving to meet the 50 percent RPS may require looking carefully at transmission needs. "As the system is changing in ways we hadn't historically anticipated," said Berberich, "we're going to have to be agile around re-evaluating the transmission system and what's really needed.

"There are lots of moving parts." *–L. D. P.*

[14.2] Cal-ISO Approves Changes to Commitment Cost-Bidding Process

The Cal-ISO Board of Governors on March 25 approved changes to the commitment cost-bidding process after weighing concerns that the proposal might hinder the use of preferred resources and did not adequately address concerns from demand-response providers.

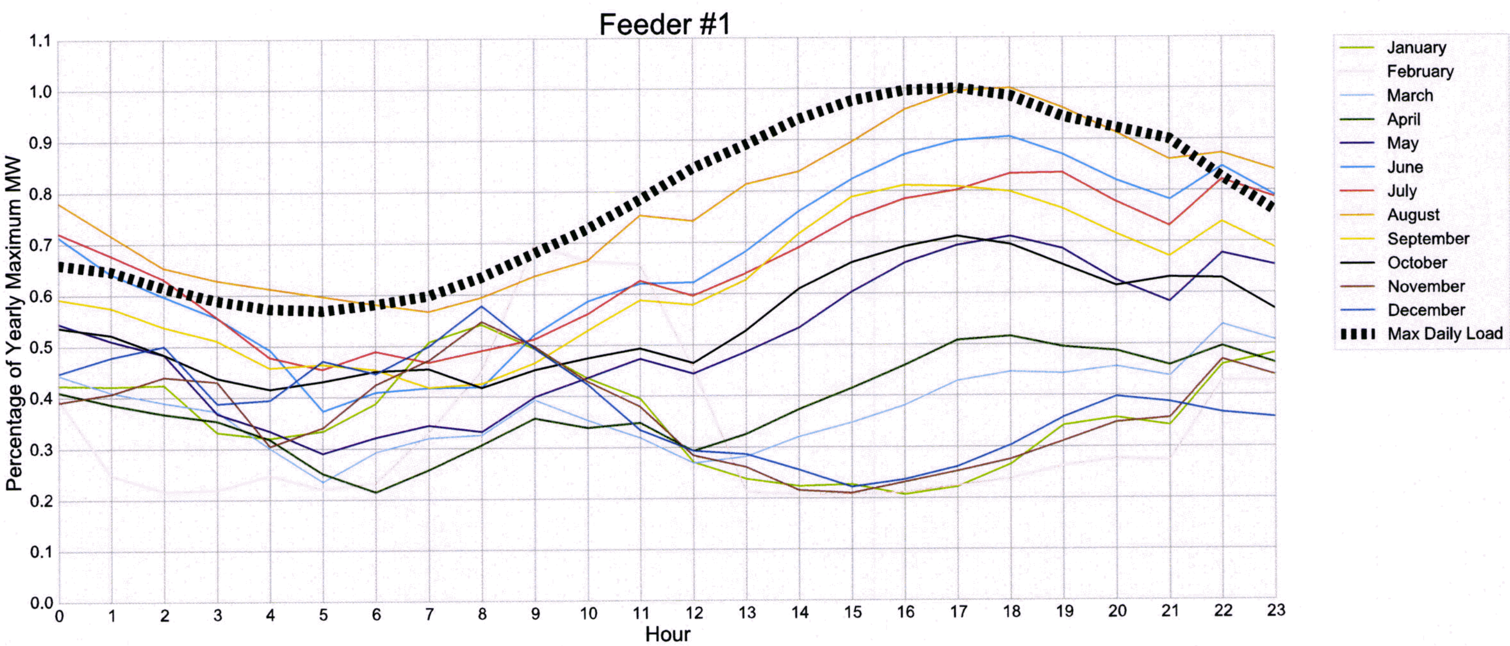
Under the changes, use-limited resources will be eligible for a calculated opportunity cost to include in their daily commitment cost bids, which will allow the market to recognize their use limitations that extend over a longer period of time than the daily markets, such as annual limitations. The move will allow the ISO to eliminate the "registered cost" option for bidding commitment costs, under which a market participant can bid fixed costs for 30 days.

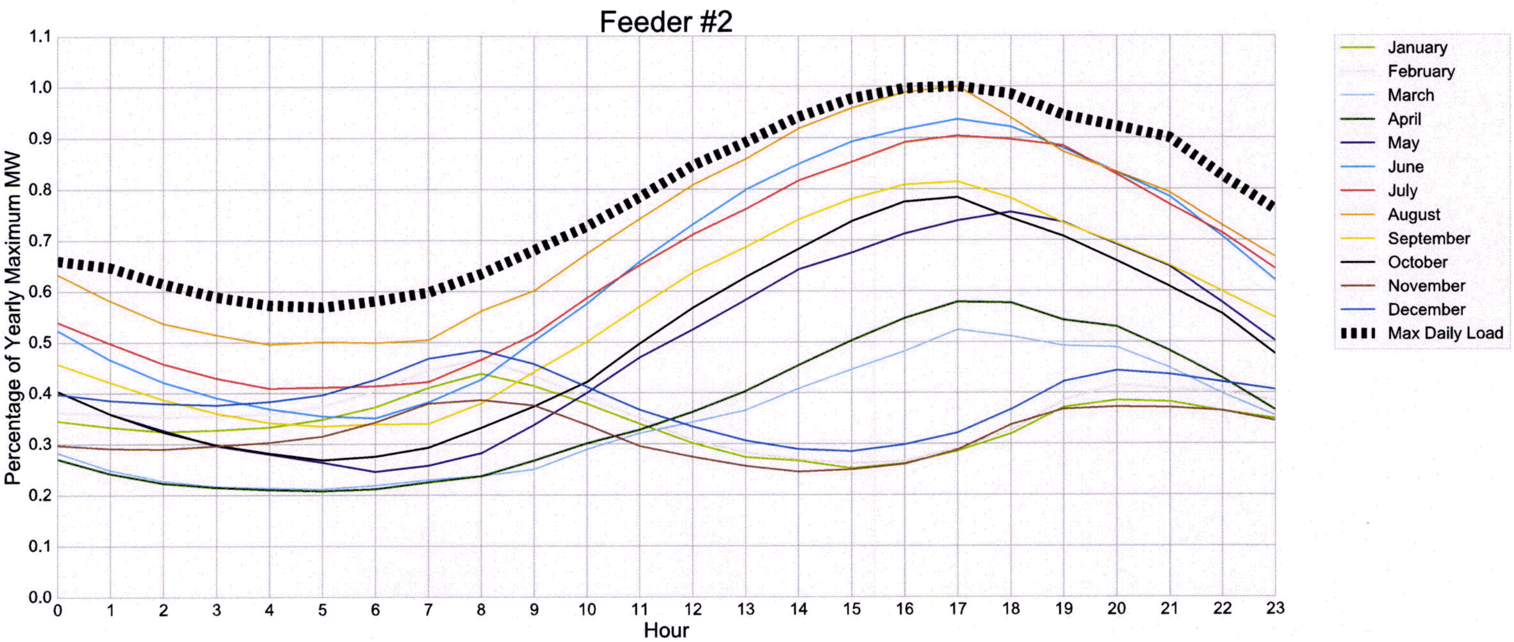
Cal-ISO now has roughly 35,000 MW of use-limited resources available. The goal is to commit these resources when they are of most value to the grid and at maximum profit for the generation owner.

The original language on commitment costs was altered to reflect comments made by CPUC Commissioner Mike Florio.

Florio's changes address concerns related to the use-limited status of preferred resources. This includes giving parties that might be affected—including investor-owned utilities, demand-response and energy-storage providers, and others—more time to better understand and manage the transition to the cost-bidding structure.

Exhibit WAM-8: Normalized Hourly Loading on Representative Feeders Figures


Feeder #1
Percentage of Yearly Maximum MW
1.1
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour
January
February
March
April
May
June
July
August
September
October
November
December
Max Daily Load



Feeder #2
Percentage of Yearly Maximum MW
Hour
1.1
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
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23
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April
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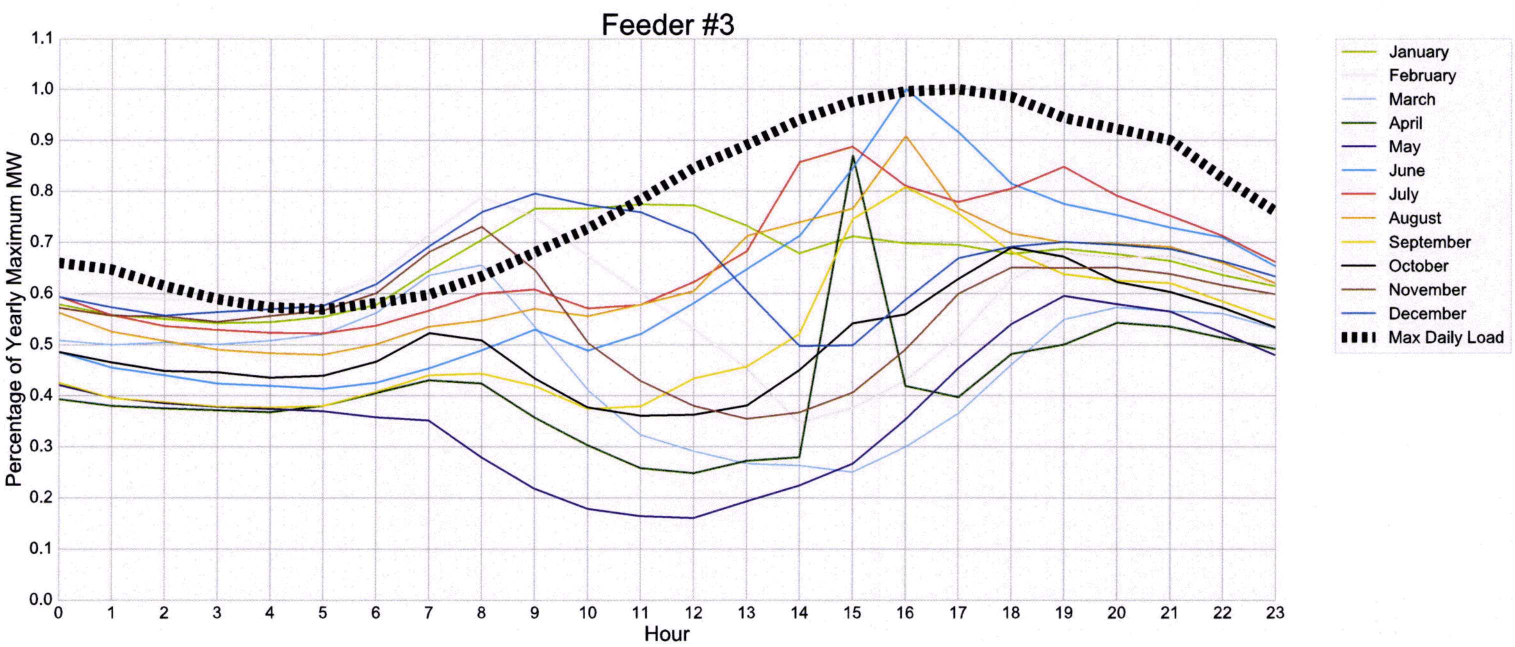
September
October
November
December
Max Daily Load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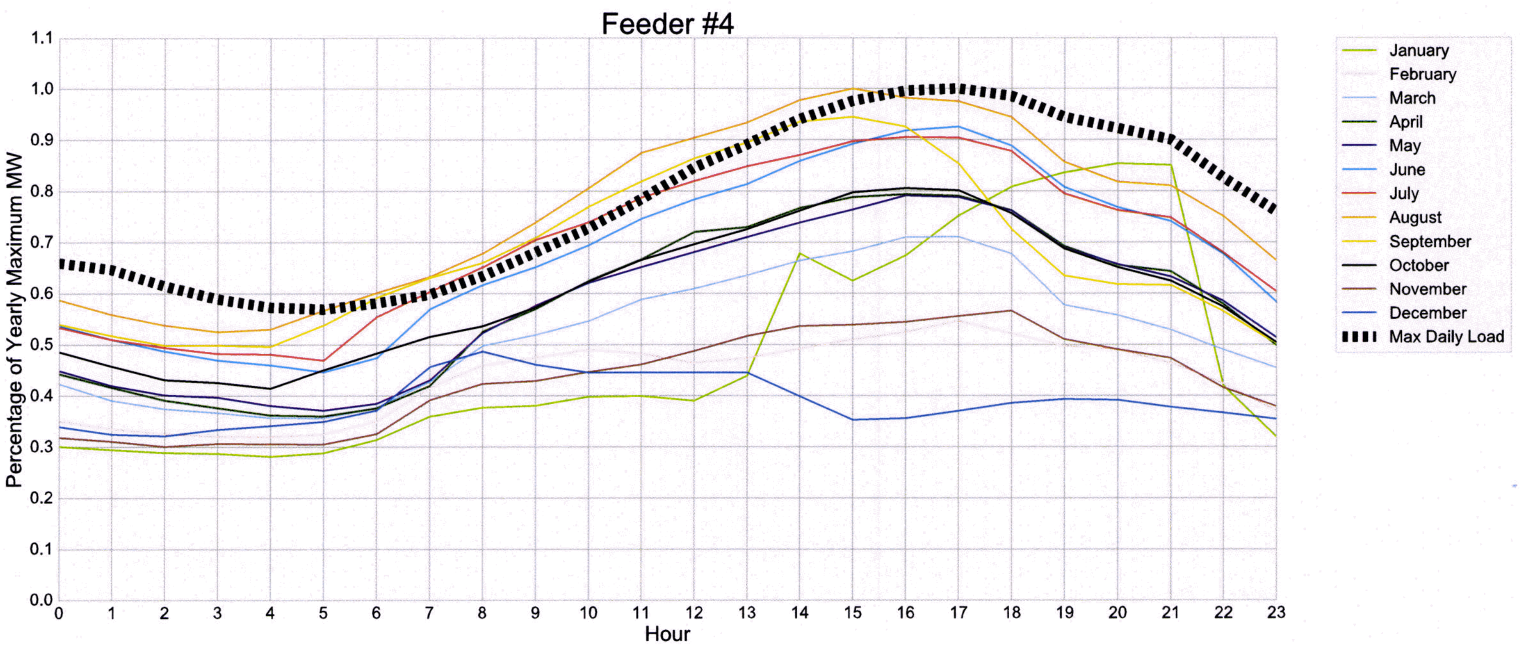
Percentage of Yearly Maximum MW
Hour
1.1
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
January
February
March
April
May
June
July
August
September
October
November
December
Max Daily Load



Feeder #4
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1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
Percentage of Yearly Maximum MW
0
1
2
3
4
5
6
7
8
9
10
11
12
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14
15
16
17
18
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Hour
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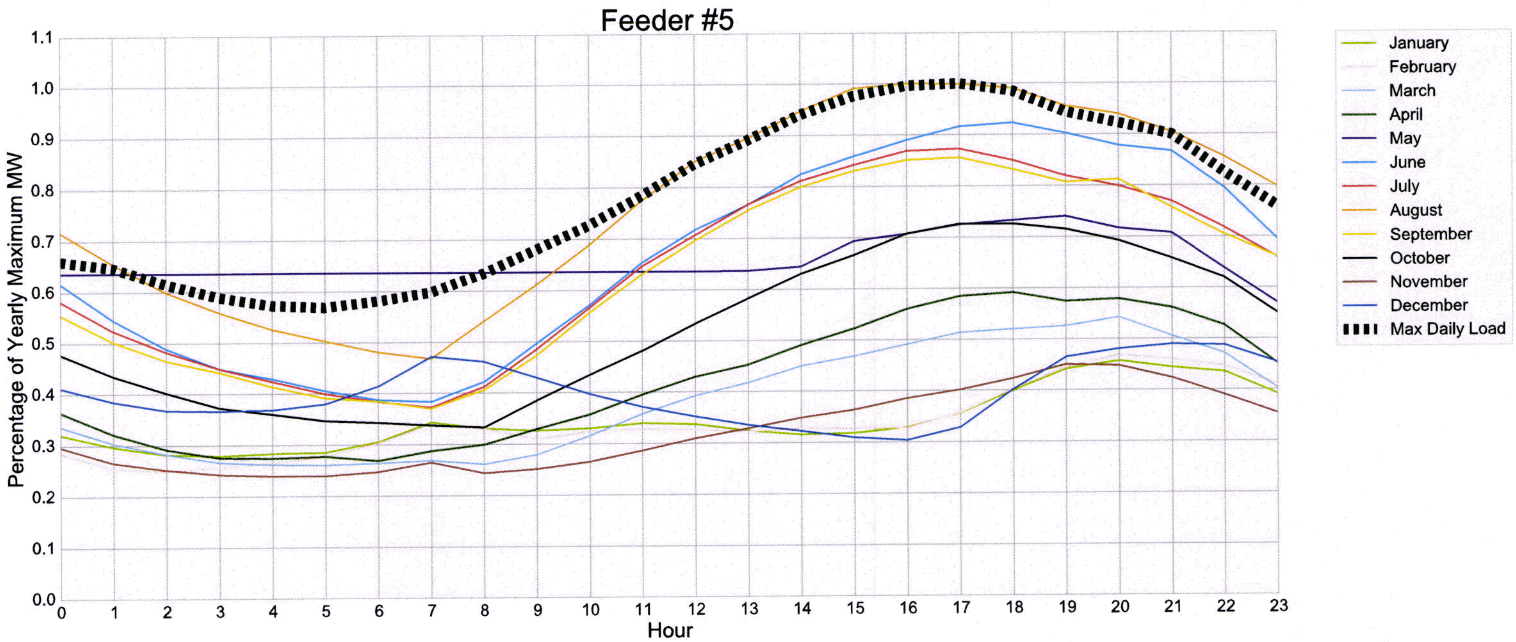
September
October
November
December
Max Daily Load



Feeder #5
Percentage of Yearly Maximum MW
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0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour
January
February
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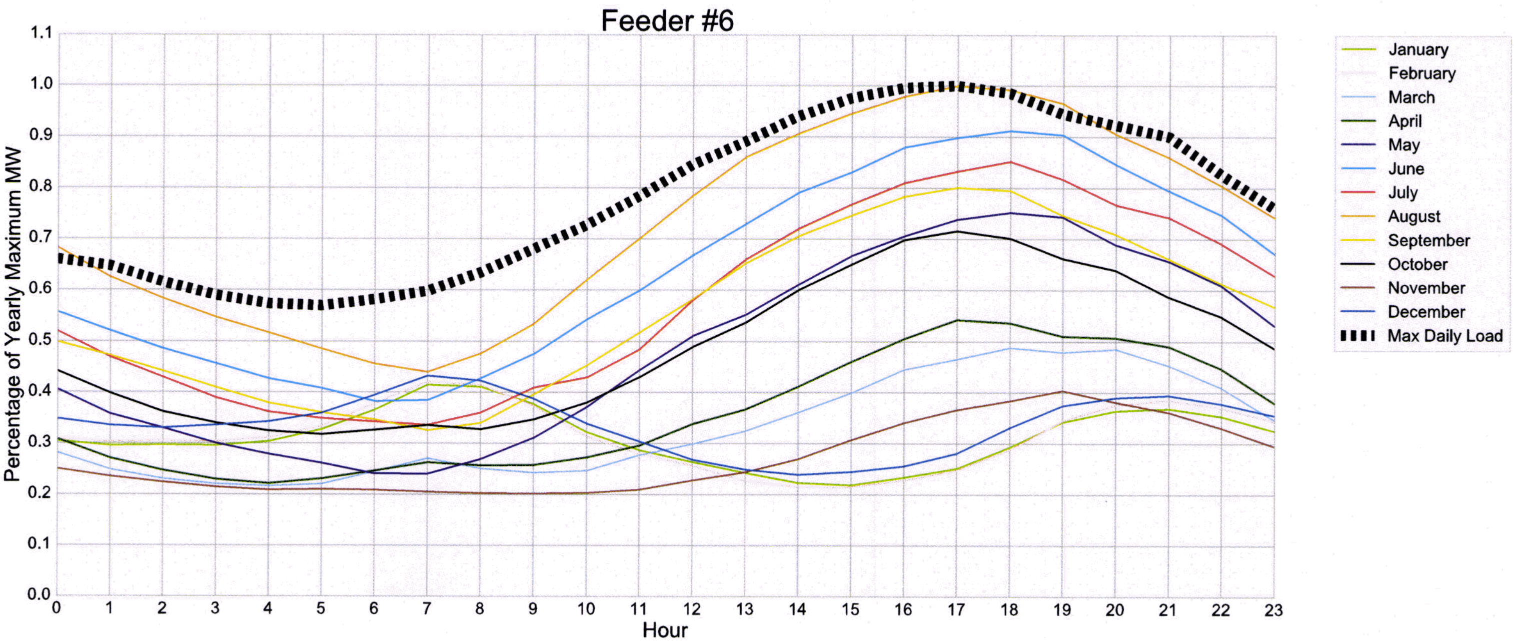
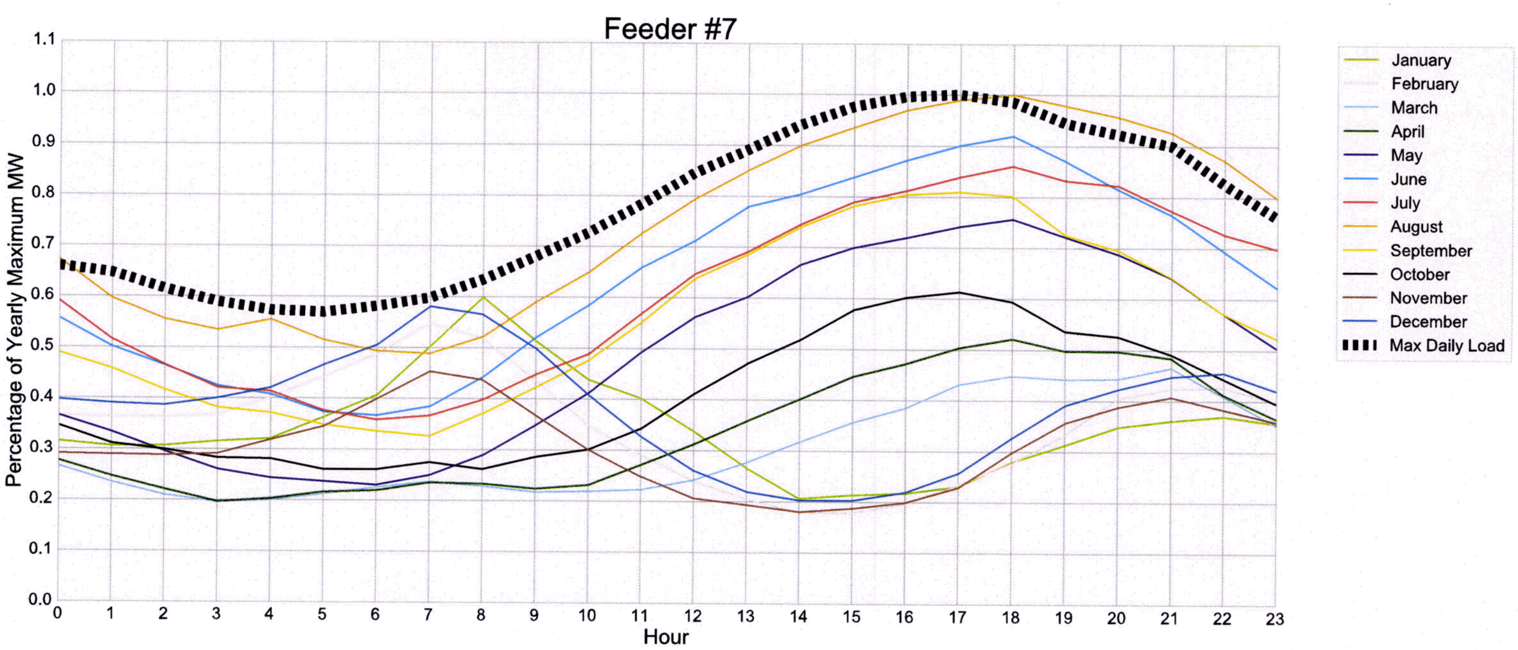
Max Daily Load



Feeder #6
Percentage of Yearly Maximum MW
Hour
January
February
March
April
May
June
July
August
September
October
November
December
Max Daily Load



Feeder #7
Percentage of Yearly Maximum MW
Hour
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1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
0
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August
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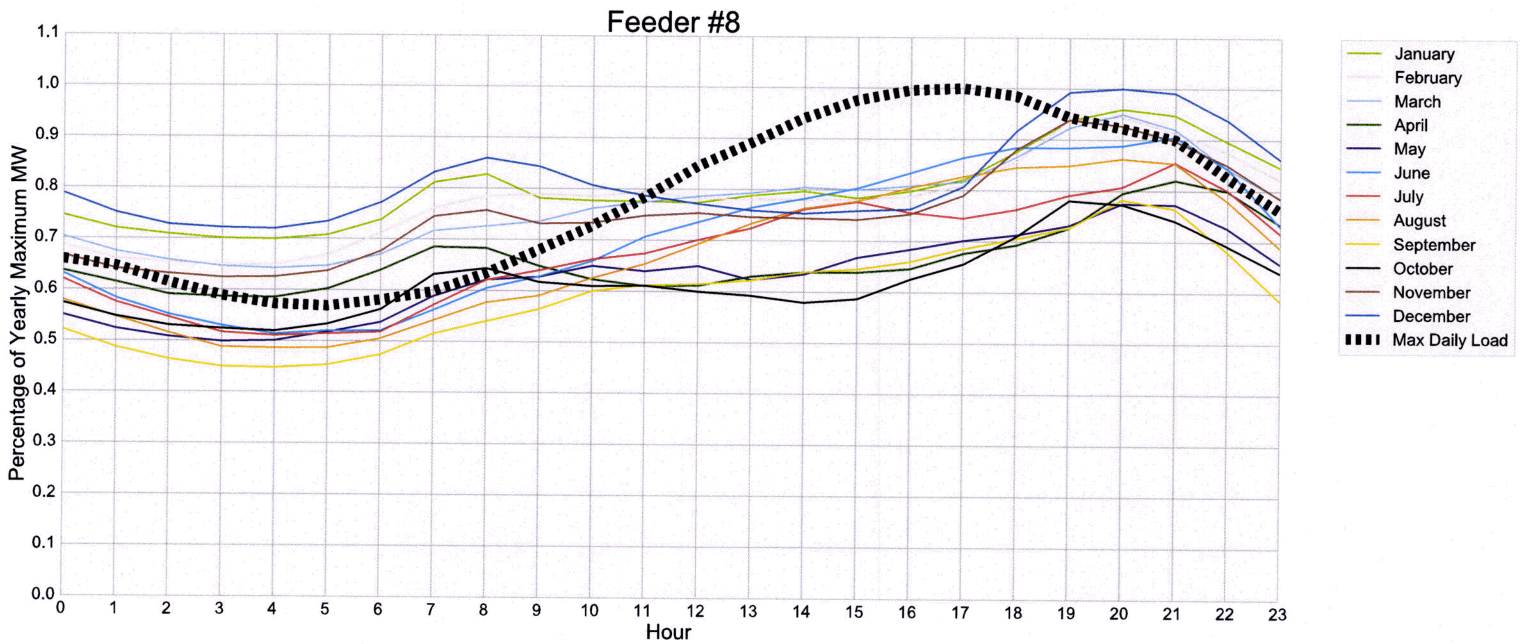
October
November
December
Max Daily Load


Feeder #8
Percentage of Yearly Maximum MW
Hour
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1.0
0.9
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0.7
0.6
0.5
0.4
0.3
0.2
0.1
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November
December
Max Daily Load

Exhibit WAM-9: Excerpt from
PG&E 2014 General Rate Case Phase II Prepared Testimony, Exhibit (PG&E-1), Volume 1: Revenue Allocation and Rate Design, Application 13-04-012

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U 39 M)	Application 13-04-012 (Filed April 18, 2013)

SETTLEMENT AGREEMENT ON MARGINAL COST AND REVENUE ALLOCATION IN PHASE II OF PACIFIC GAS AND ELECTRIC COMPANY'S 2014 GENERAL RATE CASE

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Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: July 16, 2014

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U 39 M)	Application 13-04-012 (Filed April 18, 2013)

SETTLEMENT AGREEMENT ON MARGINAL COST AND REVENUE ALLOCATION ISSUES IN PHASE II OF PACIFIC GAS AND ELECTRIC COMPANY'S 2014 GENERAL RATE CASE

I. INTRODUCTION

In accordance with Article 12 of the Rules of Practice and Procedure of the California Public Utilities Commission (CPUC or Commission), the parties to this Settlement Agreement (Settling Parties) agree on a mutually acceptable outcome to the marginal cost and revenue allocation issues in the proceeding captioned above. The details of this Marginal Cost and Revenue Allocation (MC/RA) Settlement Agreement are set forth herein.

This MC/RA Settlement Agreement is a direct result of Administrative Law Judge (ALJ) Douglas Long and Assigned Commissioner Michael Peevey's encouragement to the active parties to meet and seek a workable compromise. The active parties hold differing views on numerous aspects of PG&E's initial marginal cost and revenue allocation proposals in Phase II of this General Rate Case (GRC) proceeding. However the Parties bargained earnestly and in good faith to seek a compromise and to develop this MC/RA Settlement Agreement, which is the product of arms-length negotiations among the Settling Parties on a number of disputed issues. These negotiations considered the interests of all of the active parties on marginal cost and revenue allocation issues, and the MC/RA Settlement Agreement addresses each of these interests in a fair and balanced manner.

The Settling Parties developed this MC/RA Settlement Agreement by mutually accepting concessions and trade-offs among themselves. Thus, the various elements and sections of this

MC/RA Settlement Agreement are intimately interrelated, and should not be altered, as the Settling Parties intend that this Settlement Agreement be treated as a package solution that strives to balance and align the interests of each party. Accordingly, the Settling Parties respectfully request that the Commission promptly approve the MC/RA Settlement Agreement without modification. Any material change to the MC/RA Settlement Agreement shall render it null and void, unless all of the Settling Parties agree in writing to such changes.

II. SETTLING PARTIES

The Settling Parties are as follows[1/]:

- Agricultural Energy Consumers Association (AECA);
- California City-County Street Light Association (CAL-SLA);
- California Farm Bureau Federation (CFBF);
- California Large Energy Consumers Association (CLECA);
- California League of Food Processors (CLFP);
- California Manufacturers & Technology Association (CMTA);
- Direct Access Customer Coalition (DACC);
- Energy Producers and Users Coalition (EPUC);
- Energy Users Forum (EUF);
- Federal Executive Agencies (FEA);
- Office of Ratepayer Advocates (ORA);
- Pacific Gas and Electric Company (PG&E);
- Small Business Utility Advocates (SBUA);
- The Utility Reform Network (TURN); and
- Western Manufactured Housing Communities Association (WMA).

1/ Although the following parties have not joined the MC/RA Settlement Agreement, they have, nonetheless, affirmatively indicated that they do not oppose the MC/RA Settlement Agreement as presented herein: City and County of San Francisco (CCSF), Marin Clean Energy (MCE), Solar Energy Industries Association (SEIA), California Solar Energy Industries Association (CALSEIA), and the Modesto and Merced Irrigation Districts (MMID).

III. SETTLEMENT CONDITIONS

This MC/RA Settlement Agreement resolves the issues raised by the Settling Parties in A.13-04-012 (Phase II), on marginal costs and revenue allocation, subject to the conditions set forth below:

1. This MC/RA Settlement Agreement embodies the entire understanding and agreement of the Settling Parties with respect to the matters described, and it supersedes prior oral or written agreements, principles, negotiations, statements, representations, or understandings among the Settling Parties with respect to those matters.
2. This MC/RA Settlement Agreement represents a negotiated compromise among the Settling Parties' respective litigation positions on the matters described, and the Settling Parties have assented to the terms of the MC/RA Settlement Agreement only to arrive at the agreement embodied herein. Nothing contained in the MC/RA Settlement Agreement should be considered an admission of, acceptance of, agreement to, or endorsement of any disputed fact, principle, or position previously presented by any of the Settling Parties on these matters in this proceeding.
3. This MC/RA Settlement Agreement does not constitute and should not be used as a precedent regarding any principle or issue in this proceeding or in any future proceeding.
4. The Settling Parties agree that this MC/RA Settlement Agreement is reasonable in light of the testimony submitted, consistent with the law, and in the public interest.
5. The Settling Parties agree that the language in all provisions of this MC/RA Settlement Agreement shall be construed according to its fair meaning and not for or against any Settling Party because that Settling Party or its counsel or advocate drafted the provision.
6. The Settling Parties agree that this MC/RA Settlement Agreement addresses all marginal cost and revenue allocation issues.
7. This MC/RA Settlement Agreement may be amended or changed only by a written agreement signed by the Settling Parties.
8. The Settling Parties shall jointly request Commission approval of this MC/RA Settlement Agreement and shall actively support its prompt approval. Active support shall include

written and/or oral testimony (if testimony is required), briefing (if briefing is required), comments and reply comments on the proposed decision,[2/] advocacy to Commissioners and their advisors as needed, and other appropriate means as needed to obtain the requested approval.

9. The Settling Parties intend the MC/RA Settlement Agreement to be interpreted and treated as a unified, integrated agreement. In the event the Commission rejects or modifies this MC/RA Settlement Agreement, the Settling Parties reserve their rights under Rule 12 of the CPUC's Rules of Practice and Procedure, and the MC/RA Settlement Agreement should not be admitted into evidence in this or any other proceeding.

IV. OVERALL PROCEDURAL HISTORY

On January 24, 2013, PG&E requested, and the CPUC approved, a two-month extension of time to file its Application in Phase II of the 2014 GRC. The extension revised the filing date from February 13, 2013 (as required under the CPUC's Rate Case Plan) to April 18, 2013.

On April 18, 2013, PG&E filed A.13-04-012, related to electric marginal costs, revenue allocation, and rate design. As set forth at page 1 of that application, PG&E's marginal cost, revenue allocation and rate design proposals were intended:

> [T]o make progress in moving electric rates closer to cost of service, in order to send more economically efficient price signals and promote more equitable treatment among all customers. At the same time, PG&E balances other objectives including customer acceptance, rate stability, and simplifying electric rates to make them easier for customers to understand.

The application was protested on May 20, 2013, by ORA, TURN, Greenlining/CforAT, AECA/CFBF, and MCE.

A prehearing conference was held on June 3, 2013, before ALJ Long. The scope of issues and procedural schedule were set forth in the Assigned Commissioner's Scoping Memorandum and Ruling dated July 12, 2013 (Scoping Memo). Per the Scoping Memo, PG&E's updated testimony required under the CPUC's Rate Case Plan was due on August 2,

---

2/ Any oral and written testimony that the CPUC might require may be prepared and submitted jointly among parties with similar interests.

2013. On July 26, 2013, at PG&E's request, ALJ Long granted a two-week extension of that filing date. On August 16, 2013, PG&E updated its showing on marginal costs, revenue allocation, and rate design.

In a ruling issued October 18, 2013, ALJ Long modified the scope of A.13-04-012 to suspend work on residential rate design in anticipation that residential rate design issues would be considered in the Residential Rate Reform Order Instituting Rulemaking (RROIR, R.12-06-013), in which the CPUC would be examining and modifying residential rate structures in accordance with Assembly Bill (AB) 327.[3/] On Wednesday, November 6, 2013, ALJ Long clarified that electric master meter discounts and gas baseline quantities would not be suspended but rather would remain within the scope of GRC Phase II. On November 8, 2013, PG&E issued a notice of availability of revenue allocation and rate design models that were consistent with the suspension and deferral of residential electric rate design.

ORA served its prepared testimony on November 15, 2013, on marginal cost, revenue allocation, non-residential rate design, and residential electric master meter discounts. On December 13, 2013, fifteen intervenors (AECA, CAL-SLA, CFBF, CLECA/CMTA, CCSF, DACC, EUF, EPUC, FEA, MMID, MCE, SBUA, SEIA, TURN, and WMA) served their prepared testimony. On January 17, 2014, ALJ Long issued a ruling granting the parties' joint request for a continuance in the original schedule for Phase II of PG&E's 2014 GRC, in recognition of the parties' ongoing efforts to seek settlement, as discussed below.

V. SETTLEMENT HISTORY

Pursuant to Rule 12 of the CPUC's Rules of Practice and Procedure, on January 9, 2014, PG&E served on all parties a notice of a settlement conference to be held January 17, 2014. Immediately after that settlement conference, PG&E on behalf of the parties, emailed a request to the ALJ, and ALJ Long promptly issued an email ruling on January 17, 2014, granting the parties' request for a continuance in the schedule to allow for further settlement conferences, with settlement status reports to be filed on February 14 and March 12, 2014. On March 20, and

3/ The CPUC, accordingly, re-categorized the RROIR as a ratesetting proceeding in January 2014.

on May 21, 2014, ALJ Long granted further continuances in the schedule to allow the parties time for additional work on settlement of issues in this proceeding.

On March 13, 2014, the parties participating in settlement discussions reached an agreement in principle on the terms of this MC/RA Settlement Agreement. On March 20, 2014, PG&E orally notified ALJ Long that the active parties to the proceeding had reached settlement in principle regarding marginal cost and revenue allocation-related issues. As part of the joint settlement status reports filed in this proceeding, PG&E informed ALJ Long that the parties were continuing separate settlement discussions among sub-groups of parties interested in the remaining GRC Phase II issues, as discussed in Section VI below.

VI. SETTLEMENT TERMS

Considering and both recognizing and compromising the litigation positions taken by the individual parties, the Settling Parties agree to the revenue allocation set forth in this MC/RA Settlement Agreement. The revenue allocation amounts, percentages, and procedures agreed to in this MC/RA Settlement Agreement are reasonable and based on the record in this proceeding.

No later than July 25, 2014, PG&E and ORA will jointly serve a comparison exhibit showing the impact of the MC/RA Settlement Agreement in relation to their respective litigation positions, as required by Rule 12.1(a).

The Settling Parties agree that all testimony served prior to the date of this MC/RA Settlement Agreement that addresses the issues resolved by this MC/RA Settlement Agreement should be admitted into evidence without cross-examination by the Settling Parties.

The Settling Parties further agree to try to reach agreement on additional issues in A.13-04-012 including the remaining residential rate design issues and the non-residential rate design issues that are not resolved by this MC/RA Settlement Agreement.[4/] To the extent all of those rate design issues are not ultimately settled, the Settling Parties agree to pursue litigation in this

4/ PG&E is still conducting separate settlement discussions in the areas of: (1) small and medium commercial rate design, (2) large commercial and industrial rate design (including standby), (3) agricultural rate design, (4) streetlight rate design, (5) rates for Schedule E-Credit, and (6) limited residential rate design issues not being considered in the RROIR. If and as settlements are reached on such rate design issues, they will be submitted as supplements to this Settlement, as was done in PG&E's 2011 GRC Phase II proceeding.

proceeding on those rate design issues only, provided those issues do not affect the outcome of issues agreed upon in this MC/RA Settlement Agreement.

The Settling Parties agree that Agricultural party proposals relating to aggregation of accounts and Public Utilities Code § 744(c)'s potential requirements, as well as adjustments for the transfer of customers from flat rates to Time-Of-Use (TOU) rates, will be removed from revenue allocation discussions in this proceeding. These items will be included among the other issues to be considered in the Agricultural rate design settlement discussions, and shall be resolved in such a way as not to have revenue allocation implications when combined with other agricultural rate design changes. Specifically, any revenue loss from the transfer of customers to TOU rates or from any load aggregation proposals that may be adopted will not result in inter-class revenue transfers. The details of how this will be accomplished will be addressed with the Agricultural rate design in this proceeding.

VII. MARGINAL COSTS SETTLEMENT

This MC/RA Settlement Agreement does not adopt any of the Settling Parties' marginal cost principles or proposals as the basis for the Revenue Allocation settlement described in Section VIII below. The Settling Parties agree that this MC/RA Settlement Agreement addresses all necessary marginal cost issues including the specific marginal costs to be used solely for the purpose of establishing costs where needed for customer specific contract analysis including as required by Schedule E-31 and for analysis of contribution to margin for customers taking service under Schedule EDR. The marginal costs to be used for these analyses are provided in Appendix A to this MC/RA Settlement Agreement. Nothing in this MC/RA Settlement Agreement shall preclude any Settling Party from advocating for its preferred marginal costs in any other Commission proceeding or for the purpose of addressing specific rate design issues yet to be considered in this or other rate design proceedings.

If the Commission were to adopt new marginal costs/methodologies, the marginal cost values generated by such new methodologies shall not be used for the purpose of changing the agreed revenue allocation, as set forth in this MC/RA Settlement Agreement.

VIII. REVENUE ALLOCATION SETTLEMENT

1. Revenue Allocation Principles for the Phase II Allocation

The Settling Parties agree that electric revenue should be allocated as a result of A.13-04-012 on an overall revenue-neutral basis to preserve then-required total authorized revenue. The Settling Parties agree to the Phase II revenue allocation to be implemented as a result of this proceeding as set forth in the following Table 1. Table 1 shows the electric revenue based on present rates used to prepare this Settlement, the electric revenue that results from the Settlement, and the percentage change for both bundled and Direct Access/Community Choice Aggregation (DA/CCA) customers. The Settling Parties agree that upon implementation PG&E will target the average percentage change for every customer group shown in Table 1, but the actual results may vary based on rate and sales changes that will occur before this MC/RA Settlement Agreement is implemented. The Settling Parties agree as follows:

a. The revenue allocation percentages shown in Table 1 establish the basis for the Phase II allocation resulting from this proceeding.

b. The parties agree that rate design changes that may be considered in future settlements in this proceeding will be designed so as not to result in projected revenue shortfalls from any class. This provision includes, but is not limited to, agricultural account aggregation and any additional transition of agricultural customers from flat to TOU rates.

c. There is no agreement on the specific marginal cost values for purposes of revenue allocation.

d. There is no change to the allocation of Nuclear Decommissioning, the Department of Water Resources (DWR) bond charge, the Energy Costs Recovery Amount, the New System Generation Charge (NSGC), Greenhouse Gas Allowance Return, the Competition Transition Charge (CTC), or, for DA/CCA customers, the Power Charge Indifference Adjustment (PCIA).

e. Transmission Owner and other Federal Energy Regulatory Commission (FERC) jurisdictional rates shall be set by the FERC.

f. There is no change to the allocation of Public Purpose Program (PPP) rates except due to the recalculation of the cost of the CARE discount. PPP rates will be developed as the sum of public purpose program components:

1. The cost of the CARE discount will be determined based on the difference between CARE and non-CARE rates excluding the CARE surcharge, the California Solar Initiative cost, and the DWR bond charge. This cost will be allocated to eligible customers on an equal cents per kWh basis and collected through the CARE surcharge component of PPP rates. This requires an iterative determination of the CARE surcharge in PG&E's revenue allocation and rate design model.

2. There is no change to the methodology for setting rates for the remaining public purpose program components for the Phase II allocation.

g. After the allocations of all the revenues described above have been determined, PG&E will seek to create the following bundled and DA/CCA percentage changes agreed to in this proceeding by implementing the following three steps:

Step 1: For each customer class, set the bundled increase not to exceed 0.95 percent and the bundled decrease not to be less than -0.78 percent. For each customer class, set the DA/CCA increase not to exceed 2.60 percent and the DA/CCA decrease not to be less than -1.40 percent. In addition, the bundled residential increase will be limited to 0.50 percent. The revenue allocation mitigation methodology shall be consistent with that set forth in Exhibit PG&E-4, p. 2-12, line 11 through p. 2-13, line 2, modified to substitute the agreed limits on increases and decreases set forth above.

Step 2: At the time this agreement was signed, PG&E's revenue allocation and rate design model showed that the above limits on increases and decreases would result in full collection of PG&E's revenue based on the assumptions used in the model at that time. However, if at the time this Settlement is implemented, the use of these agreed limitations results in revenue adjustments that do not add to zero (i.e., do not collect the then-required revenue), PG&E shall allow the DA/CCA class level revenue for E-19 to adjust so that any revenue changes necessary to collect the then-required revenue are taken up by that class, provided however, the change to the DA/CCA class level revenue to E-19 is as small as reasonably possible and does not exceed the cap or floor. Similarly, for bundled customers, any necessary revenue changes necessary to collect the then-required revenue would be taken up by the residential class whose change should also be as small as reasonably possible and not exceed the cap or floor. Should these adjustments not be sufficient to collect the then-required revenue, further adjustments will be made to the revenue for all classes as necessary to collect the then-required revenue and will be as small as reasonably possible.[5/]

Step 3: As a final step, once the model is able to fully collect the then-required revenue, if the solution results in a rate increase to the bundled residential class of more than 0.50 percent, all bundled percentage changes will be increased by an identical amount until this increase is equal to the amount that the residential increase is over 0.50 percent. For example, a bundled increase not to exceed 0.98 percent for the Streetlighting and Agricultural classes, a bundled decrease not to be less than -0.75 percent for the Small, Medium, E-19, E-20 and Standby customer classes, and a bundled increase of 0.53 percent for the Residential class would result in an increase of 0.03 percent above the agreed upon level for all classes.

///

5/ Step 2 would not be required if the then-required revenue is fully collected in Step 1.

Table 1
Pacific Gas and Electric Company Phase II
Settlement Revenue Allocation Results

Bundled Class	Total Revenue at Present Rates[1]	Total Revenue at Proposed Rates	Percent Change
Residential	$5,309,098,010	$5,335,623,998	0.50%
Small Light & Power	$1,613,868,527	$1,601,320,699	-0.78%
Medium Light & Power	$1,239,640,531	$1,230,002,326	-0.78%
E-19	$1,816,293,284	$1,802,171,604	-0.78%
Streetlight	$69,901,669	$70,565,734	0.95%
Standby	$57,392,554	$56,946,327	-0.78%
Agricultural	$864,359,596	$872,571,013	0.95%
E-20T	$368,809,086	$365,941,596	-0.78%
E-20P	$577,978,010	$573,484,231	-0.78%
E-20S	$231,273,602	$229,478,926	-0.78%
Total Bundled	$12,148,614,871	$12,138,106,453	-0.09%

DA/CCA Class	Total Revenue at Present Rates[1]	Total Revenue at Proposed Rates	Percent Change
Residential	$85,603,947	$84,405,491	-1.40%
Small Light & Power	$32,281,647	$31,829,704	-1.40%
Medium Light & Power	$53,964,217	$55,367,287	2.60%
E-19	$223,887,070	$228,173,886	1.91%
Streetlight	$887,638	$910,716	2.60%
Standby	$1,707,723	$1,683,818	-1.40%
Agricultural	$3,111,140	$3,192,029	2.60%
E-20T	$50,464,260	$51,645,799	2.34%
E-20P	$121,563,706	$124,721,565	2.60%
E-20S	$44,386,361	$45,529,739	2.58%
FPP T[2]	$3,336,837	$3,554,126	6.51%
FPP P[2]	$196,285	$204,185	4.02%
FPP S[2]	$1,727,634	$1,783,220	3.22%
Total DA/CCA	$623,118,465	$633,001,568	1.59%
(1) Present rate revenue is based on rates effective May 1, 2013.			
(2) FPP revenue is combined with E-20, by voltage, for application of caps and floors.			

2. Timing of the Phase II Rate Change

If the rate change pursuant to this MC/RA Settlement Agreement occurs in 2014, it shall

Exhibit WAM-10: Excerpt from

California Public Utilities Commission, Decision15-08-005

ALJ/DUG/SCR/ek4 **Date of Issuance 8/18/2015**

Decision 15-08-005 August 13, 2015

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U39M).	Application 13-04-012 (Filed April 18, 2013)

DECISION ADOPTING EIGHT SETTLEMENTS AND RESOLVING CONTESTED ISSUES RELATED TO PACIFIC GAS AND ELECTRIC COMPANY'S ELECTRIC MARGINAL COSTS, REVENUE ALLOCATION, AND RATE DESIGN

DECISION ADOPTING EIGHT SETTLEMENTS AND RESOLVING CONTESTED ISSUES RELATED TO PACIFIC GAS AND ELECTRIC COMPANY'S ELECTRIC MARGINAL COSTS, REVENUE ALLOCATION, AND RATE DESIGN

Summary

This decision adopts eight separate settlements as proposed by the settling parties and resolves the remaining outstanding issues based on the merits of the litigated positions. This completes the current review of Pacific Gas and Electric Company's (PG&E) electric marginal costs, revenue allocation, and rate design. Adoption of these new rates will reallocate the existing authorized revenue requirement amongst the various customer classes and within those customer classes. One settlement was partially contested and this decision resolves those contested issues primarily in accordance with the proposed settlements.

Because this proceeding deals with only rate design related questions and not operating or capital costs, or how PG&E operates its electric system, there are no changes to PG&E's overall authorized revenue requirement, although individual customer's bills may change as a result of changes in rate design. Also, there is no impact on employee, customer, or public safety, again because this decision does not change PG&E's revenue requirement or have any direct impact on electric operations.

This proceeding is closed.

1. Procedural History

The proceeding has a complex history, as parties sought and were granted numerous extensions of time to complete settlement negotiations with various sub-groups of interested parties which resulted in eight separate settlements covering all but a few issues that were litigated. All settlement rules were followed and all parties had notice and opportunity to participate. The find that they contain a statement of the factual and legal considerations adequate to advise the Commission of the scope of the settlement and of the grounds for its adoption; that the settlement was limited to the issues in this proceeding; and that the settlement included a comparison indicating the impact of the settlement in relation to the utility's application and contested issues raised by the interested parties in prepared testimony, or that would have been contested in a hearing. These two findings that the settlement complies with Rule 12.1(a), allow us to conclude, pursuant to Rule 12.1(d), that the settlement is reasonable in light of the whole record, consistent with law, and in the public interest.

Based upon our review of the settlement documents we find, pursuant to Rule 12.5, that the proposed settlements would not bind or otherwise impose a precedent in this or any future proceeding. We specifically note, therefore, that neither PG&E nor any party to any of the settlements may presume in any subsequent applications that the Commission would deem the outcome adopted herein to be presumed reasonable and it must, therefore, fully justify every request and ratemaking proposal without reference to, or reliance on, the adoption of these settlements.

7. Summary of Settlements

A copy of all eight of the Settlement Agreements, fully executed by all interested parties, are available at the links below following each settlement. The final language of the settlement controls the terms and conditions of the adopted rates except as specifically modified herein. The proposed settlements are as follows:

1. Settlement Agreement on Marginal Cost and Revenue Allocation Issues, filed July 16, 2014;

http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=99753189;

2. Residential Rate Design Supplemental Settlement Agreement, filed July 24, 2014;

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=101125976;

3. Large Light and Power Rate Design Settlement Agreement, filed July 25, 2014;

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=102226995;

4. Streetlight Rate Design Supplemental Settlement Agreement, filed August 29, 2014;

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=103390568

5. Amended E-Credit Rate Design Supplemental Agreement, filed March 30, 2015;

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=151726093;

6. Medium Commercial Rate Design Settlement Agreement, filed September 5, 2014;

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=105647677;

7. Small Commercial Rate Design Settlement Agreement, filed September, 5, 2014; and

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=107147806

8. Agricultural Rate Design Settlement Agreement, filed December 2, 2014.

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=143515264.

Exhibit WAM-11: Excerpt from

California Public Utilities Commission, A.13-04-012, Settlement Agreement on Marginal Cost and Revenue Allocation in Phase II of Pacific Gas and Electric Company's 2014 General Rate Case, Appendix A, July 16, 2014

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U 39 M)	Application 13-04-012 (Filed April 18, 2013)

SETTLEMENT AGREEMENT ON MARGINAL COST AND REVENUE ALLOCATION IN PHASE II OF PACIFIC GAS AND ELECTRIC COMPANY'S 2014 GENERAL RATE CASE

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PACIFIC GAS AND ELECTRIC COMPANY

Dated: July 16, 2014

Pacific Gas and Electric Company
2014 General Rate Case Phase II, A.13-04-012

SETTLEMENT AGREEMENT ON MARGINAL COST AND REVENUE ALLOCATION
Appendix A

Marginal Generation Energy Costs:

Table 1 - 2014 Marginal Generation Energy Costs by Time of Use (TOU) Rate Period and Voltage Level (¢/kWh)

Line No.	TOU Rate Period	Voltage Level: Transmission	Voltage Level: Primary Distribution	Voltage Level: Secondary Distribution
1	Summer Peak	5.613	5.718	6.001
2	Summer Partial-Peak	4.791	4.881	5.123
3	Summer Off-Peak	3.654	3.722	3.907
4	Winter Partial-Peak	4.856	4.948	5.192
5	Winter Off-Peak	3.968	4.043	4.243
6	Annual Average	4.266	N.A.	N.A.

Marginal Transmission and Distribution Costs:

Table 2: 2014 Marginal Transmission Capacity Cost ($/kW-Yr)

Line No.	Transmission Capacity
1	34.86

Table 3: 2014 Distribution Marginal Customer Access Costs ($/Customer-Yr)

Line No.	Class	Marginal Customer Access Cost
1	Residential	73.72
2	Agricultural A	321.96
3	Agricultural B	1,457.43
4	Small L & P	323.37
5	A10 Medium L & P Secondary	638.43
6	A10 Medium L & P Primary	1,917.29
7	E19 Secondary	748.05
8	E19 Primary	6,288.92
9	E19 Transmission	6,650.02
10	E20 Secondary	5,559.77
11	E20 Primary	6,688.18
12	E20 Transmission	6,659.54
13	Streetlights	83.05
14	Traffic Control	105.91

Table 4: 2014 Marginal Distribution Capacity Costs by Operating Division

Line No.	Division	Primary Capacity ($/PCAF kW-Yr)	New Business on Primary Capacity ($/FLT kW-Yr)	Secondary Capacity ($/FLT kW-Yr)
1	Central Coast	95.45	12.31	4.00
2	De Anza	112.71	22.30	2.45
3	Diablo	52.57	20.78	4.01
4	East Bay	60.29	18.87	1.44
5	Fresno	30.31	8.05	1.61
6	Kern	31.43	7.95	1.97
7	Los Padres	40.87	9.75	2.03
8	Mission	19.87	9.90	1.81
9	North Bay	17.74	12.66	2.13
10	North Coast	42.22	12.65	3.13
11	North Valley	36.06	16.22	3.60
12	Peninsula	38.62	10.46	2.98
13	Sacramento	37.65	13.07	2.21
14	San Francisco	18.33	6.24	1.28
15	San Jose	38.50	12.18	2.79
16	Sierra	29.68	10.15	3.21
17	Stockton	38.26	8.85	2.30
18	Yosemite	45.78	17.54	2.94
19	System	37.33	11.26	2.33

Table 5: 2014 Marginal Distribution Capacity Costs by Distribution Planning Area

Line No.	Division	Distribution Planning Area	Capacity Projects Over $1MM ($/PCAF kW-Yr)	Capacity Projects Under $1MM ($/PCAF kW-Yr)	Total Primary Capacity ($/PCAF kW-Yr)	New Business On Primary Capacity ($/FLT kW-Yr)	Secondary Capacity ($/FLT kW-Yr)
1	Central Coast	Carmel Valley 12kV	0.00	31.07	31.07	12.31	4.00
2	Central Coast	Gonzales	0.00	31.07	31.07	12.31	4.00
3	Central Coast	Hollister	16.07	31.07	47.14	12.31	4.00
4	Central Coast	King City	129.50	31.07	160.57	12.31	4.00
5	Central Coast	Monterey 21kV	0.00	31.07	31.07	12.31	4.00
6	Central Coast	Mty_4kV (Monterey Bk#1F	0.00	31.07	31.07	12.31	4.00
7	Central Coast	Oilfields	0.00	31.07	31.07	12.31	4.00
8	Central Coast	Prunedale	0.00	31.07	31.07	12.31	4.00
9	Central Coast	Pt Moretti	0.00	31.07	31.07	12.31	4.00
10	Central Coast	Salinas (4/12 kV)	33.73	31.07	64.80	12.31	4.00
11	Central Coast	Santa Cruz Area	0.00	31.07	31.07	12.31	4.00
12	Central Coast	Seaside 4kV	0.00	31.07	31.07	12.31	4.00
13	Central Coast	Seaside-Marina 12kV	60.75	31.07	91.82	12.31	4.00
14	Central Coast	Soledad	0.00	31.07	31.07	12.31	4.00
15	Central Coast	Watsonvlle (12/21kV)	277.75	31.07	308.82	12.31	4.00
16	Central Coast	Watsonvlle (4kV)	0.00	31.07	31.07	12.31	4.00
17	De Anza	Cupertino	0.00	15.15	15.15	22.30	2.45
18	De Anza	Los Altos (12 kV)	130.97	15.15	146.12	22.30	2.45
19	De Anza	Los Altos (4kV)	0.00	15.15	15.15	22.30	2.45
20	De Anza	Los Gatos	101.47	15.15	116.62	22.30	2.45
21	De Anza	Mountain View	70.62	15.15	85.77	22.30	2.45
22	De Anza	Sunnyvale	108.09	15.15	123.24	22.30	2.45
23	Diablo	Alhambra	0.00	28.54	28.54	20.78	4.01
24	Diablo	Brentwood	0.00	28.54	28.54	20.78	4.01
25	Diablo	Clayton / Willow Pass	0.00	28.54	28.54	20.78	4.01
26	Diablo	Concord	22.24	28.54	50.77	20.78	4.01
27	Diablo	Delta (Split Into Bw And Pitts)	0.00	28.54	28.54	20.78	4.01
28	Diablo	Pittsburg	18.00	28.54	46.54	20.78	4.01
29	Diablo	Walnut Creek 12 kV	24.79	28.54	53.32	20.78	4.01
30	Diablo	Walnut Creek 21 kV	30.60	28.54	59.14	20.78	4.01
31	East Bay	C-D-L	128.09	8.29	136.39	18.87	1.44
32	East Bay	Edes-J	0.00	8.29	8.29	18.87	1.44
33	East Bay	K-X	0.00	8.29	8.29	18.87	1.44
34	East Bay	North	0.00	8.29	8.29	18.87	1.44
35	East Bay	South	60.14	8.29	68.44	18.87	1.44