BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	Docket No. E-04204A-15-0142

DIRECT TESTIMONY AND EXHIBITS OF BRIANA KOBOR

ON BEHALF OF VOTE SOLAR

DECEMBER 9, 2015

Table of Contents

List of Tables and Figures

List of Exhibits

1 Introduction

Q. Please state your name and business address.

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

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

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

Q. What is Vote Solar?

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

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

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

Q. Please describe your education and experience.

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

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

A. No. I have not.

Q. Have you previously testified before other regulatory commissions?

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

2 Purpose of Testimony and Summary of Recommendations

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

A. My testimony addresses certain rate design proposals put forth by UNS Electric, Inc. ("UNS" or the "Company") in its general rate case application. Among the rate design proposals in the UNS application, the Company has requested significant changes to rate design for net energy metering ("NEM") customers and modifications to the rate structure for residential and small commercial customers. The specific proposals I address in my testimony include: (1) the proposed modification of the NEM export rate from the retail rate to a Renewable Credit Rate; (2) the proposal to make a three-part tariff mandatory for NEM customers; (3) proposed changes to the Lost Fixed Cost Recovery Mechanism ("LFCR"); (4) the request to increase fixed charges for residential and small commercial customers; and (5) the request to remove the third tier in the standard residential rate. There are a number of additional proposals in UNS's application that are not addressed in my testimony, but that does not imply that I agree with those proposals. I reserve the opportunity to discuss any additional proposals not addressed in my direct testimony through surrebuttal testimony.

Q. Please describe how your testimony is organized.

A. The remainder of my testimony consists of seven major sections. In the first section I summarize the rationale UNS has provided to support the rate design proposals listed above. In the second section I examine whether that rationale supports the NEM-specific proposals put forth by UNS. In the third section I examine UNS's specific NEM proposals, including (1) UNS's request to reduce the credit NEM customers receive for excess energy exports; and (2) UNS's proposal to implement a mandatory three-part rate structure for NEM customers. I also examine the relationship between UNS's proposed rate design changes and the LFCR, and assess UNS's proposed changes to the LFCR. In the fourth section I address UNS's assessment of the impacts of its proposed NEM rate design changes. I also look at the potential implications of these proposals and examine the applicability of the Commission's NEM Rules to these proposals. In the fifth section I evaluate UNS's proposals to increase the fixed charges for all residential and small commercial customers, and to remove the third residential rate tier. In the sixth section I describe how UNS and the Commission should plan for distributed energy resources ("DERs") and the modern grid. Finally, the seventh section provides a summary of my recommendations.

Q. Please summarize your findings and recommendations.

A. UNS proposes significant changes to the existing rate structure for NEM customers. These changes would very likely curtail future DG growth in UNS's service territory if approved by the Commission. The Company claims that its proposals are necessary to address numerous problems caused by DG, such as declining retail sales, inequitable cost shifts among customers, and harmful grid impacts. However, my examination of the data reveals that NEM customers are not a significant driver of any of the problems UNS alleges. I show that DG is a minor contributor to the reduction in retail sales compared with other factors. In addition, I show that 98% of the residential customers that UNS alleges are causing an inequitable cost shift are not NEM customers. My analysis also shows that UNS has not established that DG causes significant grid impacts on the Company's system. As a result, UNS has not justified its proposals to dramatically alter NEM rates.

UNS's two primary methods to address the problems allegedly caused by DG are both significantly flawed and should be rejected. First, UNS proposes to modify the existing NEM tariff to substantially reduce the credit NEM customers receive for excess generation. I find that UNS has not provided sufficient basis for its recommendation that exports be valued at the Renewable Credit Rate. Without a full benefit/cost analysis there is no way to determine the current relationship between the retail rate and the value of NEM exports, and thus no way to determine the reasonableness of the Renewable Credit Rate. Moreover, I find significant flaws in the calculation of the Renewable Credit Rate. As a result, I recommend that the Commission reject UNS's proposal to lower the compensation rate it pays for NEM customers' excess generation and that exports continue to be valued at the retail rate until an independent benefit/cost analysis has been completed.

Second, UNS proposes to implement a mandatory three-part rate structure with a demand charge for NEM customers. I show that the proposed demand charges would not fully reflect costs associated with the system peak, and that demand charges for residential and small commercial customers would not provide an actionable price signal to help customers make informed decisions regarding their energy usage. Because most customers lack the tools to effectively respond to the price signals in demand charges, these charges would act like an additional fixed charge for residential and small commercial customers. I find that a mandatory demand charge for NEM customers would be discriminatory, and such charges are not appropriate for any residential or small commercial customers. I recommend that demand charges be offered only through optional rate tariffs for all residential and small commercial customers, including NEM customers.

In UNS's last general rate case the Commission approved the LFCR, which is a decoupling mechanism designed to address any issues related to fixed cost recovery from DG and energy efficiency ("EE"). This tool is the preferred method for addressing these issues, rather than UNS's proposals to amend the NEM tariff and introduce a mandatory demand charge for NEM customers. I recommend that the Commission reject UNS's proposal to add generation-related costs to the LFCR.

My testimony also shows that UNS has not adequately assessed how its NEM-specific proposals would impact customers. UNS's reliance on vague and hypothetical data fails to meet its burden of justifying changes to NEM rates under the Commission's rules. In addition, UNS's proposals would likely cause a significant decline in DG adoption rates in its service territory, but the Company did not asses how this would impact regulatory compliance, overall energy costs, and local employment.

I also address two aspects of UNS's proposals that would apply to all residential and small commercial customers, rather than just NEM customers. I find that a revised study of embedded and marginal costs based on a more reasonable allocation method demonstrates that current fixed charges for residential and small commercial customers are reasonable and I recommend that the

Commission reject UNS's proposal to increase fixed charges for these classes. I also recommend that the Commission reject UNS's proposal to eliminate the third residential rate tier. The Commission approved the current inclining block rate structure for the express purpose of incenting conservation, and the alleged fixed cost recovery differential between high and low-use customers under the current rate structure is reasonable.

Finally, I examine the fundamental changes happening in electricity distribution, and the implications of moving to the modern grid where consumers are more active participants. I recommend that the Commission create policies that ensure that the transition to the modern grid can happen in the most efficient manner, maximizing the benefits of distributed resources for the grid and minimizing overall customer costs.

3 UNS's Rationale for Its Rate Design Proposals

Q. Please describe the rationale UNS gives for its rate design proposals.

A. In a section of UNS's application labeled "Need for Updated Rate Design," the Company describes the rationale for its rate design proposals.[1] UNS indicates that an updated rate design is needed due to a decrease in retail sales of nearly 8% below the June 30, 2012 test year used in the last rate case.[2] UNS indicates that as a result of the lower level of sales, the Company must recover its fixed costs over a small number of kilowatt-hours ("kWh"), which can contribute to an under-recovery of fixed costs over time.[3] UNS claims that its current rate design, which recovers a portion of fixed costs through a volumetric per-kWh rate, "may have been appropriate in times of increasing customer usage and sales growth."[4] But, according to the Company, because of the decline in retail sales "this approach

[1] Application at 3:21.
[2] *Id.* at 3:22–23.
[3] *Id.* at 4:4–8.
[4] *Id.* at 4:10–11.

has created both difficulties for UNS Electric in recovering its authorized revenue requirement and inequities in recovering fixed costs from customers."[5]

Q. Does UNS describe what is behind the 8% reduction in retail sales?

A. Yes. UNS stated: "The significant decline in sales is due to several factors, including: (i) the shutdown or curtailment of operations by certain large customers; (ii) the effects of increased energy efficiency ("EE") and distributed generation ("DG"); and (iii) the slow pace of economic recovery. Sales reductions resulting from successful EE measures and DG systems were exacerbated by business closures, including the 2014 bankruptcy of UNS Electric's largest customer."[6]

Q. Does UNS provide any additional details on the rationale for its rate design proposals?

A. Yes. UNS describes three phenomena that drive the need for its rate design proposals.

1. UNS claims that the Company is experiencing declining usage per customer.[7]

2. The Company reports that "a significant proportion of UNS Electric's residential and small general service customers have little to no volumetric usage."[8] UNS says that "[t]hese customers include everything from seasonal homeowners, vacant structures and net metered rooftop PV systems."[9] The Company claims that under the current rate design, these customers do not pay "an equitable share of the fixed costs to operate and maintain the UNS Electric

[5] *Id.* at 4:11–13.
[6] *Id.* at 3:25–4:3.
[7] *Id.* at 4:14–16.
[8] *Id.* at 4:17–18.
[9] *Id.* at 4:18–19.

grid to which they are connected and on which they are dependent to continue to receive safe and reliable electric service when needed."[10]

3. UNS claims it "is also suffering lost revenues because the LFCR is not designed to capture all of the lost fixed cost revenues associated with meeting the Commission's Renewable Energy Standard and Energy Efficiency Rules."[11]

Q. According to UNS, what does the Company hope to achieve with its proposals?

A. UNS describes three "primary objectives" of the proposed rate design changes.[12] First, UNS claims that rate structures need to be updated to more closely match the price customers pay for the service they receive.[13] Second, UNS seeks to reduce the level of cross-subsidies between customers.[14] Third, UNS would like to give itself an "appropriate" opportunity to recover its fixed costs.[15]

4 UNS has not provided sufficient evidence to justify a change to its rate structure for NEM customers

Q. Does UNS's rationale described above support the NEM-related rate design proposals the Company is advocating for?

A. No. As I explain in detail below, my examination of the data reveals that DG is not a significant driver of the reduction in retail sales that UNS has experienced since the last rate case. In fact, 98% of the residential customers that UNS alleges

[10] *Id.* at 4:23–25.
[11] *Id.* at 4:27–5:2.
[12] David G. Hutchens Direct Testimony ("Hutchens Direct Test.") at 6:14–7:9 (May 5, 2015).
[13] *Id.* at 6:16–18.
[14] *Id.* at 7:1.
[15] *Id.* at 7:4.

are causing a cost shift are not NEM customers.[16] In addition, UNS has not established the existence of significant grid impacts related to DG.

4.1 Distributed Generation is not a significant driver of the reduction in UNS's retail sales

Q. UNS has indicated that retail sales decreased nearly 8% since the last rate case test year. What were the drivers of this reduction?

A. UNS attributes this reduction in retail sales to three factors: (1) loss of load from industrial and mining customers, (2) effects of increased EE and DG, and (3) the slow pace of economic recovery.[17]

Q. Have you examined the relative contribution of each of these factors to the loss of retail load?

A. Yes. I examined the decline in retail sales between the test year for UNS's last rate case (the 12 months ending June 30, 2012) and the current test year (calendar year 2014). This allowed me to gather information on the relative impact of each of the three drivers identified by UNS. Table 1 below summarizes the loss of load by customer class in Megawatt-hours ("MWh") between the last rate case test year and the current test year. The data in Table 1 confirms UNS's claim that there was an 8% reduction in retail sales between test years. Retail sales in the current rate case test year were roughly 141,000 MWh less than retail sales in the prior test year.

[16] Dukes workpaper "Graph P 13.xlsx" (Ex. BK-2 at 52); UNS Resp. to UDR 2.10 (Ex. BK-2 at 43).
[17] Hutchens Direct Test. at 5:20–23.

Table 1: Comparison of Retail Sales – Last Rate Case and Current Rate Case (MWh)[18]

	Last Rate Case	Current Rate Case	Change in Sales	Contribution to Total Reduction
Residential	850,000	816,000	-34,000	24%
Commercial	704,000	703,000	-1,000	1%
Industrial	130,000	93,000	-37,000	26%
Mining	133,000	64,000	-69,000	49%
Other	2,000	2,000	0	0%
Total	1,819,000	1,678,000	-141,000	100%

As shown in Table 1, approximately 75% of the 141,000 MWh reduction in retail sales that UNS claims is driving the need for its rate design proposals can be attributed to the first factor identified by UNS: reduced sales in the mining and industrial classes. This means that the other factors— non-industrial EE, DG impacts, and the slow pace of economic recovery—were collectively responsible for the remaining 25% of the 141,000 MWh decline in UNS's overall retail sales.

Q. Have you examined the relative impacts of the other factors?

A. Yes. I obtained data on the impact of DG on an annual basis, but not a monthly basis. This prevented me from calculating the level of DG consumed onsite by NEM customers during the prior test year, as I could not isolate data for the 12 months ending June 30, 2012. In order to approximate the impacts of DG between test years, I instead examined the difference in DG impacts between calendar year 2011 and calendar year 2014. Because the prior test year did not include the first half of 2011, these estimates are likely to inflate the values shown for DG. However, the values serve as a reasonable approximation to enable an analysis of the relative impact of DG compared to other factors.

[18] UNS Resp. to Staff 9.2 (Ex. BK-2 at 34). Numbers may not add due to rounding.

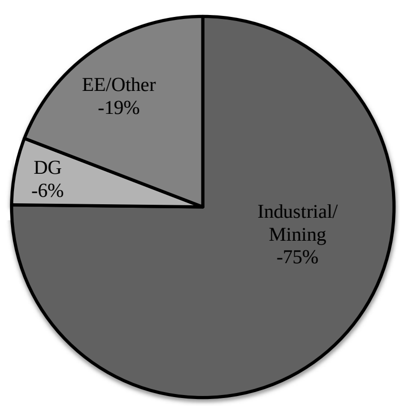
Q. What does your analysis show?

An examination of the data on the total reduction in retail sales attributed to DG between calendar year 2011 and calendar year 2014 shows that DG reduced residential load by only 8,000 MWh over that period.[19] <u>This implies that DG contributed no more than 6% to the 141,000 MWh decline in system-wide retail sales</u>.

Non-industrial EE and "the slow pace of economic recovery"[20] are responsible for the remaining 19% of the 141,000 MWh decline in retail sales not associated with reductions in the industrial and mining classes.

Figure 1 below provides a summary of the relative impact of industrial and mining reductions, DG, and non-industrial EE/economic factors on the change in retail sales between the two rate case test years.

Figure 1: Impact of Industrial and Mining Reductions, DG, and EE/Other Factors on Decline in Retail Sales Between Rate Cases[21]



As Figure 1 clearly demonstrates, when compared with other factors, DG was a minor contributor to the 8% reduction in retail sales.

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[19] UNS Resp. to Staff 2.017 (Ex. BK-2 at 25).
[20] *See* Hutchens Direct Test. at 5:20–23.
[21] Due to data limitations, the value shown for DG impact represents residential retail sales reductions due to DG between calendar years 2011 and 2014, rather than between the two test years and is therefore likely an overestimate of the DG impact between test years.

Q. UNS has also indicated that its rate design proposals would address a decline in residential usage per customer. Have you examined what has driven the reduction in residential usage per customer?

A. Yes. To support its rate design proposals, UNS points to the fact that residential usage per customer has declined 4% between 2012 and 2014.[22] Examination of the data indicates that residential usage per customer did in fact decline by roughly 4%, amounting to 398 kWh per year.[23] Additional reductions from DG, however, were minimal, amounting to an additional decline of only 13 kWh per year for the average residential customer between 2012 and 2014.[24] This indicates that 97% of the decline in residential usage per customer was driven by factors other than growth of DG.

Q. You stated above that UNS also designed its rate design proposals to address the significant proportion of residential and small general service customers that have little to no volumetric usage. Has UNS provided any additional detail on these low-usage customers?

A. Yes. In Dallas Dukes' Direct Testimony, UNS attributes this problem to the fact that nearly one in every four residential bills issued by UNS during the test year reflected usage of 300 kWh or less.[25] UNS says that "[b]ecause even a studio apartment with basic appliances and moderate usage would likely consume at least 400 kWh per month, these bills probably were generated by vacant homes, seasonal customers and DG customers."[26]

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[22] Application at 3:24.
[23] UNS Resp. to Staff 9.2 (Ex. BK-2 at 34).
[24] UNS Resp. to Staff 2.017 (Ex. BK-2 at 25).
[25] Dallas J. Dukes Direct Testimony ("Dukes Direct Test.") at 12:9–10 (May 5, 2015).
[26] *Id.* at 12:11–13.

Q. Have you been able to assess the proportion of bills amounting to 300 kWh or less that could be attributed to vacant homes, seasonal customers, and NEM customers?

A. Yes. In discovery UNS indicated that it does not track seasonal or vacant accounts.[27] However, the Company did provide data on the number of NEM customer bills that fell below the 300 kWh threshold.[28] <u>UNS reports that over 95% of the 205,129 low-usage bills were from customers who were not NEM customers.</u>[29]

Q. Have you been able to reach any conclusions regarding the contribution of DG to the reduction in retail sales that UNS claims is driving the need for its rate design proposals?

A. Yes. It is clear from the data provided by UNS that DG was not a significant driver of the reduction in retail sales that UNS claims is driving the need for its rate design proposals. Specifically, three key facts show that DG is only a minor contributor, at most, to the reduction in UNS's retail sales.

1. DG contributed less than 6% to the overall decline in retail sales—more than 94% of the decline can be attributed to other causes.

2. DG reduced average residential usage per customer by 13 kWh between 2012 and 2014, indicating that 97% of the decline in residential usage per customer was due to factors other than DG.

3. More than 95% of residential customer bills for usage under 300 kWh were from customers who were <u>not</u> NEM customers.

The data shows that the problems UNS claims warrant their rate design proposals are not DG problems. In fact, drivers such as sales declines in the industrial and mining sector and reductions due to EE and other factors, had a much larger

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[27] UNS Resp. to VS 1.05(b), (c) (Ex. BK-2 at 2).
[28] UNS Resp. to VS 1.05(d) (Ex. BK-2 at 2).
[29] *Id.*

impact on UNS's sales. Therefore, the Company should not single out NEM customers for rate reform based on the mistaken rationale that DG has caused a significant decrease in retail sales.

4.2 Ninety-Eight Percent of the Residential Customers UNS Alleges are Causing a Cost Shift are not NEM Customers

Q. Please summarize UNS's claims regarding cost shifting between customers.

A. UNS alleges that under the current rate design, lower-usage customers shift fixed costs to higher-usage customers.[30] To illustrate this problem, UNS points to three examples of low-usage customers: (1) seasonal customers; (2) vacant homes or businesses; and (3) NEM customers.[31] In addition, UNS provides a chart that claims to show that roughly two-thirds of the bills issued in the last four years to residential customers did not provide fixed cost recovery equivalent to the class average established in the most recent rate decision.[32] In the data underlying the chart, UNS shows that the usage level at which they define customers as achieving fixed cost recovery is roughly 1,000 kWh per month.[33]

Q. Does UNS discuss cost shifts that are specific to NEM customers?

A. UNS claims that "under the Company's current rates, which feature a tiered rate design that relies heavily on volumetric sales to recover fixed costs, solar DG users are not asked to pay for their fair share of the electric system. Instead, those costs are shifted to other customers."[34] The Company also points to a Commission decision regarding NEM rate design in Arizona Public Service Company's ("APS") territory as evidence that a cost shift exists in its own territory.[35]

[30] Dukes Direct Test. at 3:6–9.
[31] *Id.* at 11:5–12:6.
[32] *Id.* at 13:6–27.
[33] Dukes workpaper "Graph P 13.xlsx." (Ex. BK-2 at 52).
[34] Hutchens Direct Test. at 13:20–23.
[35] *Id.* at 14:10–12.

Q. Do you have any information to indicate what proportion of the low-usage customers UNS claims are responsible for shifting costs are NEM customers?

A. Yes. Very few of these low-usage customers are NEM customers. As described above, UNS points to problems associated with customers that use less than 300 kWh monthly. The Company suggests that these bills are related to seasonal customers, vacant homes, and NEM customers. The analysis described above reveals that NEM customers are in fact <u>less than 5% of this low-consumption cohort</u>.[36]

UNS further alleges that two thirds of residential customers (those with consumption under roughly 1,000 kWh monthly) do not pay their fair share of fixed costs. However, an examination of the level of NEM customers in that cohort reveals that NEM customer bills accounted for only <u>2% of all customer bills below 1,000 kWh</u> in 2014.[37]

Q. What do these findings show?

A. UNS complains that NEM customers do not cover their fair share of fixed costs. But NEM customers represent just 2% of the UNS customers that do not pay their fair share of fixed costs, according to the Company's rationale. In other words, 98% of the customers causing the alleged cost shifting issues UNS complains of are not NEM customers. It is unreasonable and discriminatory for UNS to address an alleged cost shift by singling out the 2% that are NEM customers for differential treatment.

[36] UNS Resp. to VS 1.05(d) (Ex. BK-2 at 2).
[37] UNS Resp. to UDR 2.10 (Ex. BK-2 at 43).

4.3 UNS has not shown that DG causes significant grid impacts

Q. Does UNS claim that DG in its service territory impacts the Company's operations?

A. Yes. Carmine Tilghman's Direct Testimony describes several grid operation considerations associated with integrating DG, and in particular distributed solar generation.[38]

Q. What DG integration issues does UNS discuss in its testimony?

A. UNS breaks the discussion of DG integration issues into three categories: (1) intermittency of generation; (2) the utility's inability to monitor and control systems; and (3) excess generation flowing back to the grid.[39]

Q. Do you have any general opinions about UNS's approach to its discussion of the impacts of DG on the grid?

Underlying UNS's discussion of each of these categories is the Company's assumption that the typical NEM customer will size their system to offset 100% of annual usage. As I discuss in a later section of this testimony, despite repeated questioning from multiple intervenors, UNS has not provided any data to support this assumption.[40] The lack of data to support this most basic premise is indicative of the imprecise nature of UNS's assertions regarding the impacts of DG on its grid. Furthermore, even if the Company were able to provide data to support this foundational assumption, UNS has failed to conduct any detailed analysis of issues related to DG on its system at either current or anticipated levels of penetration. UNS instead relies on broad national and regional studies, which may

[38] Carmine Tilghman Direct Testimony ("Tilghman Direct Test.") at 4:12–6:23 (May 5, 2015).
[39] *Id.* at 4:14–16.
[40] *See infra* at section 6.1.

or may not apply to UNS's grid and service territory. As a result, the entire discussion of grid impacts is speculative.

Q. What does UNS claim are the issues associated with intermittency of generation?

A. UNS claims that renewable generation "requires the continued services of the centralized grid to supply the necessary back-up energy and ancillary services to support solar and other intermittent renewable resources."[41] The Company also claims that "[t]his problem is exacerbated through policies such as net metering, which encourages customers to oversize their solar systems beyond their average load in order to 'bank' as many credits as possible for use later."[42] UNS reports that higher levels of intermittent generation will create greater load imbalance and fluctuations in voltage and frequency, requiring additional ancillary services.[43] UNS says that "updated rate design and large scale energy storage facilities on a system-wide basis will likely be needed to manage this issue."[44]

Q. Has UNS accurately described the issues associated with the intermittency of renewable generation?

A. In my opinion, UNS's testimony overstates the issue. First of all, UNS's assessment is based on the premise that the typical NEM customer will size its system to offset 100% of load,[45] but as shown below, there is no data to support this assumption. In addition, UNS has not provided data on any additional ancillary services that have been required on its system as a result of current DG levels in UNS's service territory. UNS has also not provided an estimate of what level of ancillary services may be required with future DG penetration.[46]

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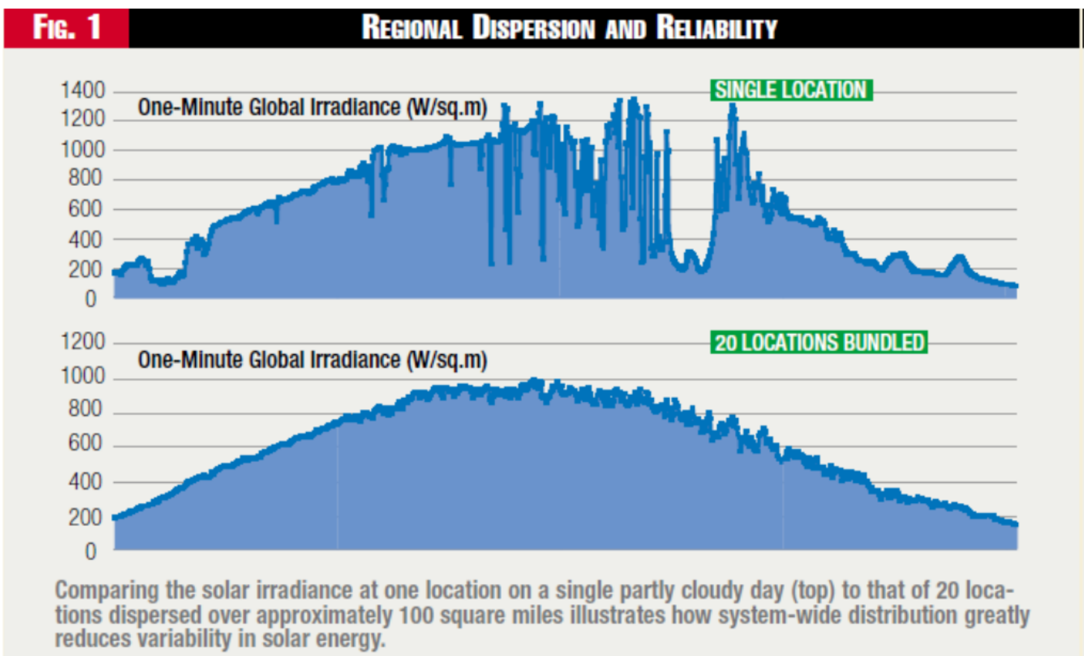
[41] Tilghman Direct Test. at 4:21–23.
[42] *Id.* at 4:24–26.
[43] *Id.* at 5:10–12.
[44] *Id.* at 5:12–13.
[45] UNS Resp. to VS 2.15 (Ex. BK-2 at 6).
[46] UNS Resp. to VS 2.17 (Ex. BK-2 at 7).

Q. Do you have any information regarding the intermittency of distributed solar generation?

A. Yes. While an individual solar photovoltaic ("PV") system may produce electricity intermittently, experiencing generation reductions with passing clouds, a group of distributed solar PV systems will have a much less intermittent generation profile. This is similar to the way in which individual customer load shapes may vary, but load shapes of groups of customers exhibit a smoother load profile. Figure 2 below demonstrates the variability in a single PV array in comparison to a group of 20 arrays.

Figure 2: Effects of Geographic Diversity on PV System Intermittency[47]



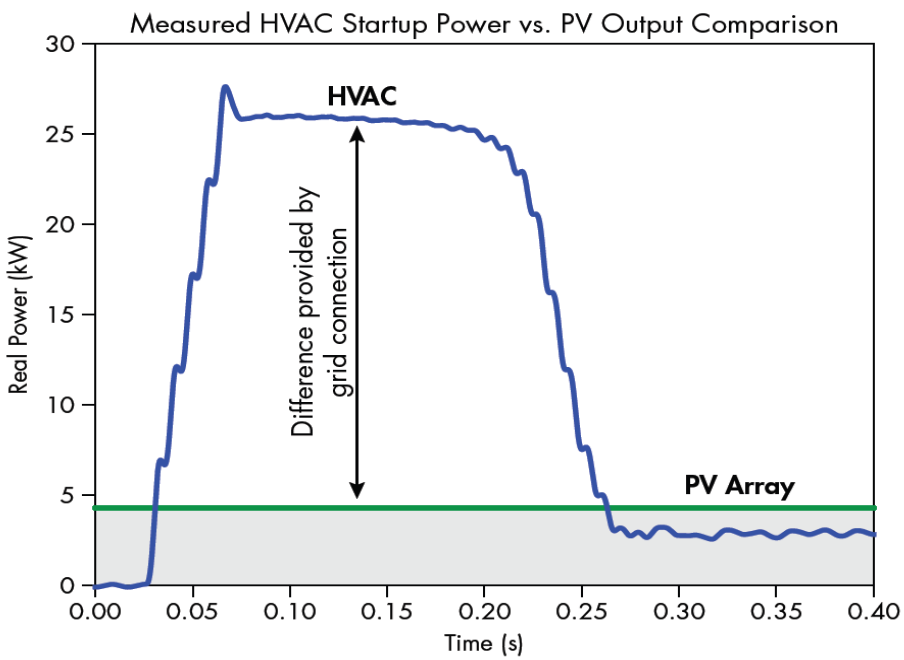
Because distributed PV systems are not uniformly intermittent, having a group of PV systems decreases variability and creates a more predictable pattern.

[47] Richard Perez et al., *Effective metrics give solar its due credit*, Fortnightly Magazine (Feb. 2009), *available at* http://www.fortnightly.com/fortnightly/2009/02/redefining-pv-capacity.

Q. Do non-NEM residential customers have perfectly predictable load profiles?

A. Absolutely not. Residential service loads are not constant; they vary throughout the day, in some cases dramatically, and utilities must stand ready to meet the entire customer load at all times. For example, when an air conditioner turns on, there is a spike in demand that can be quite high relative to a typical PV array, as shown in Figure 3 below.

Figure 3: Air Conditioning Startup Power[48]



Roughly one third of UNS customers have central AC in their homes.[49] As shown in Figure 3, if a group of air conditioners of this type started at the same time there would be significant swings in demand that may require support from additional ancillary services.

[48] Pub. Serv. Co. of Colo., Response to Questions Issued in Decision No. C14-1055-I and Attachment A, at 34 (Sept. 24, 2014), *available at* https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=411763&p_session_id=

[49] UNS Resp. to VS 3.34 (Ex. BK-2 at 23).

In addition, as adoption of electric vehicles increases in Arizona, UNS will have to accommodate large swings in residential demand as consumers plug in their electric vehicles at home charging stations. The Nissan Leaf, for example, has a 6.6 kW charger option,[50] and could result in demand swings larger than the average residential PV system size of 5 kW.[51]

Q. What does UNS claim are the issues associated with the inability to monitor and control DG systems?

A. UNS says that because DG is not connected to the utility's energy management system, the utility has no ability to see the output or control the inverter.[52] UNS claims that this creates a situation where the utility is "driving blind" and that with larger amounts of DG this situation can result in significant load to generation imbalances.[53]

Q. Do you have an opinion on UNS's claims regarding the inability to monitor and control DG systems?

A. UNS possesses sophisticated technologies that they employ to produce forecasts of PV generation on a daily and hourly basis.[54] In addition, UNS requires that DG sources install a meter to collect generation production data.[55] Interconnected PV systems above 300kW-ac are also required to install advanced metering equipment at the customer's expense that transmits real-time production data to the utility.[56] UNS uses the data obtained from these larger systems to approximate production of the smaller customer-owned DG systems.[57] Additionally, while UNS does not possess the ability to monitor all DG systems in real time, they

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[50] Nissan, 2016 Nissan Leaf Specs, http://www.nissanusa.com/electric-cars/leaf/versions-specs/version.sv.html (last visited Dec. 8, 2015).
[51] Solar Energy Indus. Ass'n, Solar Photovoltaic Technology, http://www.seia.org/research-resources/solar-photovoltaic-technology (last visited Dec. 8, 2015).
[52] Tilghman Direct Test. at 5:16–18.
[53] *Id.* at 5:18–23.
[54] UNS Resp. to Staff 2.031 (Ex. BK-2 at 28).
[55] UNS Resp. to Staff 2.033 (Ex. BK-2 at 30).
[56] *Id.*
[57] *Id.*

similarly lack the ability to monitor all individual customer load fluctuations in real time. As discussed above, fluctuations in residential demand due to HVAC systems or electric vehicle cycling can exceed PV system output. UNS has managed to "drive blind" when it comes to other customer demand fluctuations for decades. It is not credible that an inability to monitor and control each DG system presents any exceptional challenges for the utility.

Q. What does UNS claim are the issues associated with excess generation flowing back to the grid?

A. UNS claims that excess energy that is exported from NEM customer generators to the grid creates "issues on the distribution system."[58] The issues listed include the potential to exceed capacity ratings on individual transformers or feeders; significantly higher energy flows that increase operations and maintenance costs and equipment wear and tear; exported energy flowing back up through the distribution system; and potential for reverse power flow and overload conditions.[59]

Q. Do you have an opinion regarding the issues with excess generation identified by UNS?

A. UNS has revealed through discovery that the Company has not conducted any studies concerning increased operations and maintenance costs or equipment wear and tear resulting from DG.[60] The Company also has not conducted any studies on the impact of energy flowing back up through the generation system from DG.[61] UNS acknowledges that its statements were based on broad national and regional studies, rather than any analysis unique to the UNS territory and level of DG penetration.[62] In addition, UNS explicitly states that its claims regarding issues with excess generation are based on the assumption that the typical NEM

[58] Tilghman Direct Test. at 5:25–26.
[59] *Id.* at 5:25–6:23.
[60] UNS Resp. to TASC 3.2(a) (Ex. BK-2 at 48).
[61] UNS Resp. to TASC 3.2(b) (Ex. BK-2 at 48).
[62] UNS Resp. to TASC 3.2(c) (Ex. BK-2 at 48).

customer will size their system to offset 100% of load.[63] But as noted above, there is no data to support this assumption.

Q. Has UNS adequately supported its claim that excess DG generation creates significant reverse current flow issues?

No. In discovery, UNS stated that "[a] number of circuits within both UNS Electric and TEP's systems have shown to have reverse current flow on at least one phase due to distributed generation."[64] However, when further information was requested, UNS declined to quantify the number of circuits that have experienced reverse power flow, making it difficult to assess the prevalence of this issue.[65] When UNS receives a generation interconnection request, the Company may model PV generation on the distribution system using SynerGEE Electric powerflow software.[66] Through this modeling, UNS has only identified three instances where the existing distribution facilities could not support the proposed generation source.[67] In two of those instances, upgrading the existing overhead feeder conductor was identified as a possible solution.[68] And in the third instance, power factor correction at the generation facility was found to mitigate the problem.[69] Again, the data do not indicate that this is a common issue on the UNS system.

Q. Has UNS adequately supported its claim that excess DG generation requires additional investments related to frequency control and power factor correction?

No. Craig Jones' Direct Testimony states that a "DG customer may require additional investments in the distribution system to provide frequency control and

[63] Tilghman Direct Test. at 6:5–6.
[64] UNS Resp. to VS 2.24 (Ex. BK-2 at 10).
[65] UNS Resp. to VS 3.21 (Ex. BK-2 at 21).
[66] UNS Resp. to VS 3.24(b) & Staff 2.035 (Ex. BK-2 at 22, 31).
[67] UNS Resp. to VS 3.24(d) (Ex. BK-2 at 22).
[68] UNS Resp. to VS 4.4(c) (Ex. BK-2 at 24).
[69] *Id.*

power factor correction."[70] However, when asked in discovery to identify any expenditures related to investments in the distribution system due to NEM customers, UNS replied that it "has not attempted to track and assign all of the additional costs associated with the above impacts caused by the addition of these partial requirements customers, but is certain none of these services can be provided without additional costs."[71] This assumption is not necessarily true. Rather than requiring additional investments such as UNS describes, DERs, including demand response and distributed storage, can provide frequency control. Smart inverters can also provide power factor correction, as well as voltage and frequency control. As I discuss below, proactive planning for efficient DER deployment can avoid the need for capital investments and reduce overall costs for all customers.[72]

Q. In your opinion, has UNS adequately demonstrated that DG in the Company's service territory causes significant grid impacts?

A. No. It is clear from the information provided by the Company that UNS's claims regarding the impacts of excess generation on the grid are not based on an analysis of the utility's own system. The limited impacts that UNS has been able to identify on its own system do not point to a large-scale problem due to these issues.

5 UNS's Proposals To Reduce DG Growth Are Flawed And Should Be Rejected

Q. What NEM-specific proposals will you address in your testimony?

A. I address UNS's proposal to reduce the NEM export rate and the proposal to require that NEM customers take service on a three-part tariff. I will additionally address the relationship between the proposed NEM rate changes and the LFCR.

[70] Craig A. Jones Direct Testimony ("Jones Direct Test.") at 15, n.4 (May 5, 2015).
[71] UNS Resp. to VS 3.03(c) (Ex. BK-2 at 13).
[72] *See infra* at section 8.

5.1 The Commission should not approve UNS's proposed amendments to the NEM tariff

Q. What is net metering?

A. The Commission's rules define "net metering" as follows:

> "'Net Metering' means service to an Electric Utility Customer under which electric energy generated by or on behalf of that Electric Utility Customer from a Net Metering Facility and delivered to the Utility's local distribution facilities may be used to offset electric energy provided by the Electric Utility to the Electric Utility Customer during the applicable billing period."[73]

Net metering means when a NEM customer generates excess energy that is delivered to UNS, the customer has the right to correspondingly offset their electricity purchases from the Company. The NEM customer is thus entitled to a one-to-one energy offset under which the NEM customer is compensated for their energy exports at the retail rate.

Q. How has UNS proposed to amend the current NEM tariff?

A. UNS has proposed to decrease the credit NEM customers receive for their excess generation. Specifically, UNS has proposed to implement a new NEM tariff for customers submitting an application for interconnection after June 1, 2015, which would eliminate the compensation of NEM customers' excess generation at the retail rate. Instead, UNS would compensate NEM customers for their exports at the "Renewable Credit Rate."[74] UNS is additionally requesting a partial waiver of Rule R14-2-2306 to "eliminate the 'roll over' of excess generation to offset future usage."[75] In place of the excess generation roll over, UNS proposes that NEM

[73] A.A.C. R14-2-2302(11).
[74] Tilghman Direct Test. at 7:3–5, 8:18–21.
[75] *Id.* at 7:6–7.

customers taking service under the new rider be able to "carry over unused bill credits to future months if they exceed the amount of their current bill."[76]

Q. What is the Renewable Credit Rate?

A. UNS's proposed Renewable Credit Rate is based on the most recent utility-scale renewable energy purchased power agreement ("PPA") connected to UNS or sister company Tucson Electric Power's ("TEP's") distribution system.[77] UNS proposes that the Renewable Credit Rate be updated annually with the Company's REST filing and that it would be based on the most recent comparable utility-scale PPA.[78] The Renewable Credit Rate proposed in this application is based on a PPA signed December 17, 2014, for a 21.5 MW ground mounted PV system.[79] The initial Renewable Credit Rate based on this PPA would be set at 5.84¢/kWh.[80]

Q. Has UNS discussed its rationale for compensating NEM customers for excess generation at the Renewable Credit Rate, rather than at retail rates?

A. UNS witness Dukes claims that adoption of the Renewable Credit Rate "is a further step to send more accurate price signals to net metered customers about their true energy costs."[81] He additionally testifies that the rate will "partially alleviate the bypass of fixed cost recovery that occurs when customers self-generate a portion of their energy requirements,"[82] and that it "will reduce but not eliminate the subsidy" to NEM customers.[83]

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[76] Dukes Direct Test. at 20:1–2.
[77] Tilghman Direct Test. at 7:14–17.
[78] *Id.* at 8:4–9.
[79] UNS Resp. to VS 3.01(b)–(d) (Ex. BK-2 at 11).
[80] Tilghman Direct Test. at 7:14–15.
[81] Dukes Direct Test. at 4:20–21.
[82] *Id.* at 20:18–20.
[83] *Id.* at 22:27.

Q. Do you have an opinion on UNS's rationale for the Renewable Credit Rate proposal?

A. As demonstrated in earlier sections of this testimony, when compared to the impact of declining sales to industrial and mining customers and EE/other reductions, DG is an insignificant cause of the reduced retail sales that the Company claims are driving the need for its rate design proposals. In addition, as shown above, NEM customers account for less than 2% of the residential customers that UNS claims do not pay their fair share of the fixed costs of UNS's system. Because UNS's justifications for reducing DG levels are unsupported by the evidence, the Commission should reject its attempt to reduce DG adoption by decreasing the retail rate credit NEM customers receive for excess generation. In addition, to the extent that UNS claims compensation for DG exports shifts costs to other customers on the UNS system—a contention I also dispute—focusing on the cost shift UNS attributes to NEM customers would be unduly discriminatory because NEM customers would represent just 2% of such customers.

Q. Why do you dispute UNS's contention that compensating NEM exports at the retail rate shifts costs to other customers?

A. UNS has not provided any evidence in this proceeding to establish whether or not the current NEM tariff design, including compensation for NEM exports at the full retail rate, results in any cost shift either to or from NEM customers. The question of whether a cost shift exists depends on the relationship between the retail rate credit and the value of exported solar generation. UNS has provided <u>no evidence</u> on which to analyze the relationship between the Company's retail rate and the value of exported solar generation. Before the reasonableness of the proposed Renewable Credit Rate can be assessed, the Commission must establish the value of the exported DG for which the Renewable Credit Rate is intended to compensate. Because there has been no assessment of the value of distributed solar on the UNS system, there is no basis on which to conclude whether retail rate compensation is too high or too low, or if a cost shift exists (and in which direction).

Q. What evidence is needed in order to assess the relationship between the value of solar and the retail rate?

A. In order to determine the relationship between the value of distributed solar and the retail rate, a full benefit/cost analysis would need to be completed. To produce a reliable and reasonable result, it is vital that an unbiased party completes the benefit/cost analysis and that the analysis is comprehensive in scope. Different approaches to value of solar studies can produce large variations in the result, as evidenced by studies completed of the APS system. In 2013, competing studies sponsored by APS and the solar industry concluded that the value of solar was 3.56¢/kWh and 21–24¢/kWh, respectively.[84] The Commission must guide the development of the benefit/cost analysis for UNS's service territory to ensure that any future analysis produces a reliable result.

Q. Are there any guidelines for how a benefit/cost analysis should be conducted?

A. Yes, the Interstate Renewable Energy Council has developed a useful guidebook on the calculation of the costs and benefits of distributed solar generation that can inform the Commission's process.[85] The guidebook builds on experiences throughout the country to propose a standardized and reliable approach to the analysis. The guidebook recommends that policy makers consider the following categories of benefits and costs, and provides guidance on their calculation:

- Avoided Energy Benefits
- System Losses
- Generation Capacity

[84] Interstate Renewable Energy Council, Inc., *A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation* 5 (Oct. 2013), *available at* http://votesolar.org/wp-content/uploads/2013/09/IREC_Rabago_Regulators-Guidebook-to-Assessing-Benefits-and-Costs-of-DSG1.pdf.
[85] *Id.*

- Transmission and Distribution Capacity
- Grid support services
- Financial services
- Security services
- Environmental services
- Social services
- Customer costs
- Utility costs, and
- Decline in value for incremental solar additions at high market penetration.[86]

Before the Commission adopts an alternative export credit such as the Renewable Credit Rate, it should assess the relationship between the retail rate and the value of distributed solar by analyzing each of these categories of costs and benefits.[87]

Q. Does evidence from other states suggest that NEM rates result in a cost shift from NEM to non-NEM customers?

A. No, in fact, evidence from other states suggests that the value of solar may exceed the retail rate. And in some cases, the value of distributed solar exceeds the retail rate by a significant amount. As discussed above, the results of distributed solar benefit/cost analyses can differ greatly depending on the assumptions and perspective of the entity sponsoring the study. As a result, it is important to look at studies sponsored or performed by an independent party, such as a state agency. A number of notable studies have been sponsored by independent state entities concluding that the benefits that distributed solar generation provides to the utility exceed the costs. Table 2 below summarizes the results of recent studies performed by or for state governments.

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[86] *E.g.*, *id.* at 36, 42.

[87] The Commission is currently seeking to address these issues in Docket No. E-00000J-14-0023, and Vote Solar has intervened in that proceeding.

Table 2: Recent Benefit/Cost Studies

State	Date	Sponsor	Resulting Value
ME	1-Mar-2015	Legislature	33.7¢/kWh levelized[88]
MS	19-Sep-2014	PSC	17.0¢/kWh levelized[89]
NV	Jul-2014	PUC	18.5¢/kWh levelized[90]
MN	31-Jan-2014	Dep't of Commerce	14.5¢/kWh levelized[91]
VT	1-Oct-2014	Legislature	23.7¢/kWh levelized[92]

This experience in other states shows that the existence of a cost shift should not be assumed in this proceeding. As the studies in Table 2 demonstrate, state sponsored studies have found that the benefits of solar can be as high as 25-30¢/kWh in some jurisdictions. Without evidence on the benefits and costs of solar in the UNS territory, the Commission has no means to determine the need for an alternate export rate, nor a basis on which to evaluate the appropriateness of UNS's proposed Renewable Credit Rate.

Q. If the Commission elects to consider an alternate export rate, do you have any comments on the specific aspects of the Renewable Credit Rate proposal?

A. Yes. If the Commission decides to consider an alternate credit rate despite the lack of evidence on the benefits and cost of distributed solar, there are several significant flaws in UNS's proposed Renewable Credit Rate.

[88] Me. Pub. Utils. Comm'n, *Maine Distributed Solar Valuation Study* 6 (Apr. 2015), *available at* http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-FullRevisedReport_4_15_15.pdf.

[89] Elizabeth A. Stanton et al., Synapse Energy Econ., Inc., *Net Metering in Mississippi: Costs, Benefits, and Policy Considerations* 43 (Sept. 2014), *available at* http://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf.

[90] Energy & Envtl. Econ., *Nevada Net Energy Metering Impacts Evaluation* 93 (July 2014), *available at* http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study.

[91] Peter Fairley, *Minnesota Finds Net Metering Undervalues Rooftop Solar*, IEEE Spectrum (Mar. 24, 2014), *available at* http://spectrum.ieee.org/energywise/green-tech/solar/minnesota-finds-net-metering-undervalues-rooftop-solar.

[92] Vt. Pub. Serv. Dep't, *Evaluation of Net Metering in Vermont Conducted Pursuant to Act 99 of 2014*, at 17 (Nov. 2014), *available at* http://psb.vermont.gov/sites/psb/files/Act%2099%20NM%20Study%20Revised%20v1.pdf.

Q. What are the flaws in the Renewable Credit Rate proposed by UNS?

A. The flaws in the proposed Renewable Credit Rate are threefold: (1) the Renewable Credit Rate does not appropriately approximate the value of distributed solar generation; (2) the Renewable Credit Rate would be extremely volatile and vulnerable to gaming; and (3) the Renewable Credit Rate would violate the Commission's existing NEM rules.

Q. Why do you contend that the Renewable Credit Rate does not appropriately approximate the value of distributed solar generation?

A. UNS rationalizes linking the Renewable Credit Rate to the most recent renewable PPA connected to the generation system based on the assertion that "as long as the Company has a renewable energy requirement and would otherwise be procuring renewable energy, it [is] reasonable to pay the prevailing wholesale market price for renewable energy on our distribution grid."[93] But crediting DG exports at utility-scale renewable rates ignores many key benefits provided by DG that are not provided by utility-scale renewables. Distributed solar's unique benefits compared to utility-scale solar generation include higher generation capacity value due to the geographic diversity of DG systems, potentially greater avoided distribution costs and grid services from DG, and greater local employment benefits accruing from DG.

UNS attempts to treat DG and utility-scale solar as interchangeable renewable energy sources, but Arizona and other states have recognized that this is not the case. For example, the Arizona Renewable Energy Standard ("RES") sets a 15% renewables requirements by 2025, and 30% of that requirement must be met with DG.[94] The Commission thus recognizes that DG and utility-scale solar are not fungible resources. Moreover, several other states' renewable energy standards contain similar DG carve outs acknowledging that DG and utility-scale solar are

[93] UNS Resp. to TASC 1.13(d) (Ex. BK-2 at 46).
[94] A.A.C. R14-2-1804, R14-2-1805.

not equivalent.[95] UNS's attempt to equate the value of DG and utility-scale solar without a proper assessment of DG's costs and benefits should be rejected.

Q. Why would the proposed Renewable Credit Rate be volatile and subject to gaming?

A. UNS has proposed to base the Renewable Credit Rate on the single most recent contract and to update the rate annually. Utility supply contracts are complex agreements with pricing and terms established through a closed-door negotiation process, often with price escalators and performance-oriented terms. In fact, UNS has indicated that even the Company itself cannot predict future Renewable Credit Rates.[96] By setting the Renewable Credit Rate based on a single PPA, UNS has made the rate subject to large annual fluctuations. This can be seen through examination of utility-scale solar prices from recent TEP PPAs. The PPA used as the basis for UNS's proposal has a rate of 5.84¢/kWh, while another contract signed by TEP has a rate as high as 10.875¢/kWh.[97] A Renewable Credit Rate that could fluctuate so widely from year to year would subject NEM customers to significant uncertainty and volatility, potentially making financing of projects more difficult and expensive.

These fluctuations additionally make the proposed Renewable Credit Rate vulnerable to gaming. Since the rate would be based on the single most recent contract at the time of filing, UNS would have an incentive to time the finalization of more costly renewable PPAs in order to minimize the rate it would pay to compensate NEM customers.

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[95] *See, e.g.*, Colo. Rev. Stat. § 40-2-124(1)(c)(I)(E), (1)(c)(II)(A) (3% DG carve out by 2020, with half of that requirement from retail DG); 20 Ill. Comp. Stat. 3855/1-56(b) (1% DG carve out, with half of that requirement from systems smaller than 25 kW); Minn. Stat. § 216B.1691 subdiv. 2f(a) (1.5% solar carve out, with 10% of that requirement from DG systems smaller than 20 kW); N.M. Code R. § 17.9.572.7(G) (3% DG carve out).
[96] UNS Resp. to TASC 1.13(d) (Ex. BK-2 at 46).
[97] UNS Resp. to VS 3.01(f) (Ex. BK-2 at 11).

Q. Why do you say that the Renewable Credit Rate would violate the Commission's existing NEM rules?

A. As I discussed above, Commission Rule R14-2-2302 defines net metering to give NEM customers the right to a one-to-one retail rate offset for excess generation. In addition, Commission Rule R14-2-2306(C) states:

> "If the kWh supplied by the Electric Utility exceed the kWh that are generated by the Net Metering Facility and delivered back to the Electric Utility during the billing period, the Customer shall be billed for the net kWh supplied by the Electric Utility in accordance with the rates and charges under the Customer's standard rate schedule."[98]

This concept of a one-to-one retail rate offset for excess generation is so fundamental to NEM policy that it is the reason this rate design is called "net" energy metering in the first place: the exports must "net" against consumption at the retail rate. While I am not a lawyer and I am not offering a legal opinion, it seems clear that UNS's proposal to reduce the compensation rate for excess generation would not be net metering and would thus violate the existing NEM rules.

Q. Has UNS requested a partial waiver of Rule R14-2-2306 as part of its proposal?

A. Yes, UNS has requested a partial waiver of Rule R14-2-2306 to "eliminate the 'roll over' of excess generation to offset future usage."[99] However, the Company has not addressed the fact that its proposal also violates the NEM rules by proposing to take the "net" out of net energy metering. The Commission has previously stated that compensation for exports at the retail rate is a fundamental part of the NEM rules. In Appendix B to Decision 69127 adopting the Renewable Energy Standard and Tariff Rules, the Commission explicitly addressed the question of customer compensation for generation supplied to the grid.[100] Faced

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[98] A.A.C. R14-2-2306(C).
[99] Tilghman Direct Test. at 7:6–7.
[100] Decision No. 69127 at App. B 1:19–6:20 (Nov. 14, 2006).

with proposals, including a proposal from APS, to delete the requirement crediting exports at the full retail rate, the Commission concluded that "Net Metering is an important piece of the regulatory infrastructure for distributed generation" and did not approve APS's proposed change.[101] UNS's proposal would violate Commission rules, and the "partial waiver" it has requested would not cover the deviations from the NEM rules that the Company proposes.

Q. What are your recommendations regarding the proposed Renewable Credit Rate?

A. Commission rules dictate that UNS must compensate NEM customers' exported DG at the retail rate. Absent any evidence to reliably determine whether the current retail rate is above or below the value of DG on the UNS system, there is no basis on which to support a departure from the current NEM compensation structure. In addition, the proposed Renewable Credit Rate has several significant flaws. Therefore, even if the Commission decides to consider an alternate export rate, the proposed Renewable Credit Rate should be rejected.

5.2 Demand charges should not be mandatory for NEM customers, or any other residential or small commercial customers

Q. What is UNS proposing regarding demand charges for residential and small commercial customers?

A. The Company has proposed to implement optional tariff schedules for residential and small commercial customers that include a demand charge, in addition to the basic service charge and volumetric energy charge. This type of rate design is referred to as a "three-part" rate structure. UNS has proposed that a three-part rate structure be mandatory only for NEM customers.[102] While the Company has not

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[101] *Id.* at 2:2–5, 6:8–9.
[102] Dukes Direct Test. at 4:1–2, 5:2–3.

proposed mandatory three-part rates for all residential and small commercial customers at this time, it hopes to "make such a move possible in the future."[103]

Q. What is the rationale that UNS provides in support of demand charges for residential and small commercial customers?

A. UNS claims:

> "Three-part rates more fairly allocate costs to the customers within a class that 'cause' them and provide proper price signals that help customers make informed decisions regarding their energy and electrical system usage. Three-part rates also reward customers for better load factors and reductions in peak usage – attributes that lead to lower system costs, which benefits all customers."[104]

In addition, UNS points to eight other utilities that offer residential rates that include demand charges.[105]

Q. Do you agree that the demand charge proposed by UNS better reflects utility costs than the current rates that include only a basic service charge and volumetric energy charges?

A. No. UNS has proposed to charge customers based on the hour of maximum measured demand in the billing month, regardless of the time of day in which that demand occurs.[106] Many of the costs that UNS allocates to the demand charge are associated with the system peak, rather than individual customer peaks. Data on the annual UNS system peak for the last five years shows that the system peak can be expected to occur in the mid-afternoon during the summer months.[107] A residential customer, on the other hand, may set her peak demand in the early morning while making coffee, and using the clothes dryer and hair dryer. Therefore, it is not clear that a demand charge based on the individual customer peak, which can occur at any time day or night, would result in fair allocation of costs among customers within the residential and small commercial classes.

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[103] *Id.* at 18:6–13.
[104] *Id.* at 17:11–15.
[105] *Id.* at 16:22–17:6.
[106] Jones Direct Test. Ex. CAJ-3 (Proposed RES-01 Demand tariff).
[107] UNS Resp. to WRA 1.06 (Ex. BK-2 at 50).

Q. Do you agree that demand charges would send price signals that help customers make informed decisions regarding their energy and electrical system usage?

A. I do not. In order for a rate structure to send a price signal to help customers make informed decisions, the customers must be able to understand how to respond to that price signal. In the case of demand charges, residential and small commercial customers would first need to know when their peak demands occur. Because the demand charge would be assessed based on the highest hour of consumption in a given billing period, there would be an average of 730 hours in which each individual customer's peak demand may occur. Moreover, the day of the week and hour of the day in which that peak occurs may vary from month to month. In addition, to gain an understanding of when their peak demand may occur in any given month, the customer would also need to understand how common behaviors such as staying home sick from work, having friends over for a poker night, or hosting an annual family holiday may impact the level and timing of their peak demand. Even if the typical residential customer were to have this level of understanding of their peak demand, it is not clear how that customer would be able act to reduce their peak demand.

Making an informed decision to respond to the price signal of peak demand can happen in one of two ways: through behavioral changes or through adoption of enabling technologies. As described above, it is unlikely that the average residential customer who spends only a few minutes a month focused on their electric bill will possess the information necessary to modify behavior in response to demand charges without enabling technologies. In fact, it is most likely that a mandatory demand charge would function as an additional fixed charge for residential and small commercial customers. While enabling technologies may in fact allow residential and small commercial customers to manage peak demand over time, these technologies are uncommon, costly to implement, and have not achieved widespread adoption. This fact supports demand charge rates as an optional tariff, but shows that they are not appropriate for mandatory implementation.

Q. Why do you say that a mandatory demand charge would likely function as an additional fixed charge for residential and small commercial customers?

A. A mandatory demand charge would likely function as an additional fixed charge for most residential and small commercial customers because they lack the tools and understanding to effectively respond to the demand charge price signal. This is confirmed by survey evidence from California, which found that customers compared a demand charge to a fixed customer charge because they failed to comprehend the basic mechanics of the demand charge.[108] A survey of customers in Ontario who are familiar with time-of-use ("TOU") rates had similar results:

> "The concept of maximum use during peak times is difficult for people to understand and raised concern among a few. There is no template for measuring maximum use that people are used to in the way they understand TOU. It was not obvious how this would be calculated.
>
> Without precise details of this there was concern expressed by some that small lapses in their conservation efforts will mean they will have to pay a high price for that (even if they conserve diligently on the vast majority of days during peak times). So there will be questions of fairness if they have conserved on the vast majority of days during peak demand times and essentially helped to reduce peak consumption."[109]

Q. How do you interpret these customer survey results?

A. The customers in Ontario are calling out the "gotcha" element of demand charges. Residential customers who elect to purchase only energy efficient appliances, invest in home weatherization, and turn off lights in rooms when not in use could be penalized with a high demand charge that occurs during a single hour of the month—for example, when they prepare to host their child's birthday party and

[108] Hiner & Partners, Inc., *RROIR Customer Survey Key Findings* 12, 22 (Apr. 16, 2013), *available at* http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M065/K932/65932012.PDF (App. A.1).
[109] Gandalf Grp., *Ontario Energy Board: Distribution Charge Focus Groups* 9 (Oct. 2013), *available at* http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2012-0410/Appendix%20B%20-%20Gandalf%20Distribution%20Focus%20Groups.pdf.

happen to be running the air conditioning, baking a cake in the oven, and running the clothes dryer at the same time. This concept is not just a hypothetical. The experience of Arizona public schools has shown similar results.

For example, the Mingus Union High School District ("Mingus") in Cottonwood implemented $1.1 million in energy savings measures during the 2013-2014 fiscal year.[110] These measures included lighting replacements, HVAC replacements, installation of an energy management system, and behavioral conservation efforts resulting in a decrease in electric consumption of nearly 30%.[111] However, when APS added a demand charge to their rate schedule, Mingus saw their savings from these investments evaporate.[112] Even for a school district that has much greater resources to manage energy consumption than the average residential or small commercial customer, demand charges can be difficult to respond to.

Q. UNS states that at least eight other utilities offer residential rates that include demand charges. Are these demand charges mandatory?

A. Generally not. While UNS claims that at least eight utilities in nine states offer residential rates that include a demand charge, they do not mention the fact that in all but one of these cases, the demand charge rate is optional. The only instance of a mandatory demand charge is in Salt River Project ("SRP") territory, where a demand charge was implemented earlier this year for customers with DG. While there has been much rhetoric in the UNS application about the need to "modernize" the rate structure, movement towards mandatory demand charges for all residential customers is in no way reflective of modern trends in ratemaking. Importantly, no regulatory commission in the nation has approved mandatory demand charges for residential customers.

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[110] Dr. Paul Tighe, Superintendent, Mingus Union High Sch. Dist., *Why Rates Matter: Case Studies of the Effect of Energy Rates on Users*, at slide 5 (Nov. 7, 2015), *available at* http://www.ariseia.org/download/AEATC/Why_Rates_Matter_Panel.pdf.
[111] *Id.*
[112] *Id.*

Q. Do other utilities' experiences with demand charges shed light on customers' ability to respond to such charges?

A. UNS specifically mentions that APS has an optional demand charge residential rate, which has been in effect since the 1980s and currently has 10% enrollment.[113] In a case study of its optional residential demand rate, APS explains that it "helps customers select the best rate at time of new service through [its] website rate comparison tool."[114] Not surprisingly, an examination of the relative size of residential customers that have self-selected onto the demand rate reveals that they have an average monthly consumption that is nearly three times the average monthly consumption of customers on the default rate.[115] Because the optional demand rate also includes a much lower volumetric rate, it is likely that the vast majority of APS customers who have chosen to take service on the demand rate have done so because it would lower their bills without any modification in consumption patterns. Current enrollment in APS's optional demand rate does not imply that customers in APS's territory have the ability to respond to the price signal set by demand charges. To the contrary, the fact that APS has marketed its optional demand charge rates for upwards of three decades with only 10% current enrollment demonstrates that 90% of APS's customers have either not gained an understanding of how the demand charge rate would impact them, or they have decided that the demand charge rate is not the best option for them.

Q. Can you provide any additional information on the SRP demand charge?

A. In February 2015, SRP approved a demand charge for new residential NEM customers that it estimated would increase costs for these customers by about $50 per month. After this rate was put into effect, applications for SRP's DG program

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[113] Dukes Direct Test. at 17:7–8.
[114] Meghan Grabel, APS, *Residential Demand Rates: APS Case Study* 3 (June 25, 2015), *available at* http://www.ksg.harvard.edu/hepg/Papers/2015/June%202015/Grabel%20Panel%201.pdf.
[115] *Id.* at 7.

fell by 95%.[116] Both the SRP experience and the evidence from APS's optional demand charge make clear that the majority of residential customers do not fare well under demand charges.

Q. UNS has proposed to make the demand charge mandatory only for NEM customers, what is the rationale for this proposal?

A. UNS makes two claims to support mandatory demand charges for NEM customers. First, UNS claims that "two-part rates are designed to recover costs based on average consumption levels for full-requirements customers."[117] According to UNS, because NEM customers offset some of their energy requirements through onsite generation, the current rates that do not include a demand charge "are ill-equipped in accounting for how these customers use UNS Electric's system."[118] Second, UNS claims that requiring NEM customers to take service on a rate with a demand charge will help to mitigate the cost shift they allege is occurring.[119]

Q. Is there any evidence to support these claims?

A. In order to address these claims it is important to think about what makes NEM customers different from other customers. The difference is twofold: (1) NEM customers typically use DG to supply some proportion of their energy requirements and consume the balance of energy from the grid, and (2) NEM customers may export excess generation from their DG system to the grid.

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[116] Bobby Magill, *New Fees May Weaken Demand for Rooftop Solar*, Climate Central, Nov. 11, 2015, *available at* http://www.scientificamerican.com/article/new-fees-may-weaken-demand-for-rooftop-solar/.
[117] Dukes Direct Test. at 5:1–2.
[118] *Id.*at 4:26–5:1.
[119] *Id.* at 5:3–4.

Q. Do UNS's NEM customers have different consumption patterns than non-NEM customers?

A. UNS has not provided any evidence as to whether the load factors and energy requirements from NEM customers differ significantly from the load factors and energy requirements of non-NEM customers. In the Company's own words: "The Company has no actual data on whether monthly peak loads of residential customers with DG on the UNS Electric system differ from those of residential customers without DG."[120]

Even if UNS were to provide data on whether and how NEM customers' consumption patterns differed from non-NEM customers' consumption patterns, it would not automatically justify differential rate treatment for NEM customers. The residential and small commercial rate classes each inevitably contain customers with widely-varying consumption patterns, yet these diverse customers are subject to the same rate design. For example, cooling technology can drive significant differences in customer load factors, and urban customers with higher population density can have a lower per-customer cost to serve than rural customers who may require lengthy line extensions.

Any difference between the consumption patterns of NEM and non-NEM customers would have to be significantly greater than the inevitable diversity within the residential and small commercial classes in order to warrant a rate design singling-out NEM customers. Discriminatory rate treatment of NEM customers due to differing consumption patterns would be a slippery slope toward segregation of other portions of the residential and small commercial classes (e.g., by cooling equipment or urban vs. rural customers). Piecemeal subdivision of the residential and small commercial classes in this manner would add significant complexity and may harm low- and fixed-income ratepayers.

[120] UNS Resp. to WRA 1.15 (Ex. BK-2 at 51).

In addition, UNS has claimed that “two-part rates are designed to recover costs based on average consumption levels for full-requirements customers.”[121] This claim, however, is false. UNS neglected to isolate NEM customers as a sub-class in their cost of service study, electing instead to group NEM customers with the rest of the residential and small commercial classes.[122] As a result, the two-part rates proposed by UNS were designed to recover costs based on average consumption for the entire residential and small commercial classes, including NEM customers.

Q. Would a mandatory demand charge for NEM customers reduce the alleged cost shift between NEM and non-NEM customers?

A. No, UNS’s claim that a mandatory demand charge would help mitigate a cost shift is also unsupported by the evidence. To the extent that UNS contends NEM customers cause a cost shift by offsetting a portion of their energy requirements with DG, the data analyzed in an earlier section of this testimony shows that DG has not been a significant driver in the reduction of retail sales. In addition, NEM customers do not represent a meaningful proportion of the customers UNS alleges are causing a cost shift due to low level of usage. In fact, NEM customers represent just 2% of the customers who do not pay their fair share of fixed costs according to UNS’s rationale. There is also no evidence that compensating NEM customers for DG exports at the retail rate overvalues their excess generation and creates a cost shift.

Q. Would NEM customers respond differently to the demand charge price signal than other residential and small commercial customers?

A. NEM customers are similarly situated to other residential and small commercial customers regarding the ability to understand and respond to demand charges. DG systems are effective at reducing the customer’s consumption of energy supplied by the utility, but they can have little impact on individual customer peak demand.

[121] Dukes Direct Test. at 5:1–2.
[122] UNS Resp. to VS 1.04 & Staff 2.079 (Ex. BK-2 at 1, 32).

This is because the timing of the customer's peak may occur outside the hours in which the DG system is operating. This is illustrated by UNS's own assumptions in its assessment of a hypothetical NEM customer who sizes their DG system to offset 100% of load. UNS's analysis assumes that the NEM customers' peak demand will be equivalent to the non-NEM customer's peak in all but 4 months of the year. In those 4 months, the peak demand will be reduced by 6% or less.[123] UNS has stated that it "has no actual data on whether monthly peak loads of residential customers with DG on the UNS Electric system differ from those of residential customers without DG."[124]

Q. What does this imply about UNS's proposal to make demand charges mandatory only for NEM customers?

A. UNS's proposal to require demand charges for NEM customers would effectively function as an additional fixed charge, because most NEM customers lack the ability to effectively respond to the price signal in demand charges. Imposing additional fixed charges solely on NEM customers would be unduly discriminatory because UNS has not provided evidence that NEM customers shift costs to other customers, nor that NEM customers constitute a meaningful proportion of the residential customers that allegedly do not pay their fair share of fixed costs.

Q. What do you recommend in regards to demand charges in this application?

A. I recommend that UNS's proposed demand rates for residential and small commercial customers be approved only as optional rate schedules for customers with and without DG.

[123] Dukes workpaper "RES Demand-DG_04-29-15_FINAL_v1.xlsx" (Ex. BK-2 at 54).
[124] UNS Resp. to WRA 1.15 (Ex. BK-2 at 51).

5.3 The Commission has already approved a mechanism to address under-recovery of fixed costs through the LFCR

Q. If the Commission does not approve UNS's proposed changes to the NEM tariff and its mandatory demand charge for NEM customers, will UNS be able to address the under-recovery of fixed costs resulting from DG-reduced sales?

A. Yes, the LFCR adopted in UNS's last general rate case is specifically designed to address under-recovery of fixed costs due to DG and EE.

Q. What is the LFCR?

A. The LFCR is a partial decoupling mechanism that supports EE and DG "at any level or pace set by this Commission."[125] The LFCR was agreed upon through settlement negotiations during UNS's last general rate case and reflects a compromise between UNS, Commission Staff, and the Residential Utility Consumer Office ("RUCO"). The LFCR "is intended to recover a portion of distribution and transmission costs associated with residential, commercial and industrial customers when sales levels are reduced by EE and DG, but is not intended to recover lost fixed costs attributable to generation and other potential factors, such as weather or general economic conditions."[126] In this manner, the LFCR appropriately balances UNS's desire to recover fixed costs with Commission policy that promotes certain levels of EE and DG adoption.

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[125] Decision No. 74235 at 24:12 (Dec. 31, 2013).
[126] *Id.* at 11:21–24.

Q. How is the LFCR applied to customer rates?

A. The LFCR is applied to rates as percentage-based charge on total Delivery Service and Power Supply Charges. The current LFCR is 0.6985% for EE and 0.1693% for DG.[127] This means that EE-related charges are more than four-times the level of DG-related charges, but both charges are small. UNS estimates that the average residential customer pays only 61¢/month for the EE-related LFCR and 15¢/month for the DG-related LFCR.[128]

Q. How does the LFCR relate to the NEM rate design changes proposed by UNS?

A. UNS claims that its proposed NEM rate design changes are needed to ensure greater recovery of fixed costs.[129] However, a transparent and targeted rate mechanism designed specifically to compensate UNS for lost fixed costs due to EE and DG already exists: the LFCR. In discovery, UNS states that while the LFCR was designed to recover a portion of the costs not paid by partial requirements customers, "[i]mproving cost recovery through rate design is a much better option."[130] In my opinion, addressing fixed cost recovery through the LFCR is a more transparent and efficient method than the proposed rate design. The current LFCR, unlike UNS's other proposals, does not create a disincentive for EE and DG.

Q. Why is the LFCR a better method to address fixed cost recovery than UNS's rate design proposals?

A. Rate decoupling mechanisms, such as the LFCR, are useful tools that enable policy makers to separate utility revenue streams from the volume of sales. The Commission has recognized the value of sales reduction measures, including EE

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[127] UNS Electric Statement of Charges (Jan. 1, 2014), *available at* https://www.uesaz.com/doc/customer/rates/electric/UES-801.pdf.
[128] UniSource Energy Servs., Lost Fixed Cost Recovery Mechanism, https://www.uesaz.com/news/updates/LFCR/ (last visited Dec. 8, 2015).
[129] *E.g.*, Dukes Direct Test. at 20:18–20.
[130] UNS Resp. to VS 3.08(e) (Ex. BK-2 at 14).

and DG, and has promoted certain levels of these activities through targeted policies. Under the current utility business model (i.e., return on rate base regulation), a reduction in sales can be problematic, not just because it results in fewer units of energy over which to spread fixed costs, but also because a reduction in sales can delay or eliminate the need for future infrastructure investments that the utility could add to its rate base thus boosting earnings.

UNS's preferred approach is to recover fixed costs through unavoidable fixed charges.[131] But this approach would undermine the Commission's efforts to increase EE and DG by making these measures less cost-effective, as lower per kWh volumetric rates decrease the value of each kWh saved by EE and DG. Indeed, UNS has stated that "an over-dependence on fixed cost recovery through volumetric energy charges creates an economic disincentive for the utility to promote conservation, EE, and DG."[132] The LFCR has been designed precisely to address that disincentive and to compensate the utility accordingly.

Contrary to UNS's statement, the LFCR is the better option to address lost fixed cost recovery from EE and DG. As a targeted decoupling mechanism, the LFCR appropriately compensates UNS for sales lost to EE and DG, while maintaining appropriate price signals to customers that indicate the value in conservation. The LFCR thus ultimately reduces energy costs for all ratepayers.

Q. Has UNS proposed to maintain the LFCR that was approved in the last Settlement?

A. No. UNS has proposed a number of changes to the LFCR. Among the proposed changes, UNS has requested the addition of generation related costs in the LFCR.[133] UNS has additionally proposed a number of other changes to the LFCR that are not addressed by my opening testimony. I reserve the opportunity to address these additional proposals in surrebuttal if necessary.

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[131] Jones Direct Test. at 38:5–8.
[132] *Id.* at 36:20–21.
[133] *Id.* at 74:25–75.3.

Q. Do you agree that generation related costs should be included in the LFCR?

A. I do not. UNS states that while it agreed to the exclusion of generation costs in the settlement, the Company did not agree with excluding generation costs in theory and it is now asking that these costs be added to the LFCR.[134] UNS claims its generation assets are necessary to meet current and anticipated load, and that it incurred these asset costs to serve all customers, including those who have reduced consumption due to EE and DG.[135] However, according to its most recent Integrated Resource Plan ("IRP"), UNS-owned generating assets, including the newly acquired interest in Gila River, account for just over 60% of the utility's capacity obligations.[136] UNS must acquire nearly 40% of its capacity obligations on the market or through future commitments. UNS thus has the ability to take projected levels of EE and DG into account as it procures capacity needed to meet its remaining resource adequacy obligations. As a result, UNS is able to avoid fixed generation costs associated with EE and DG, and these costs should therefore be excluded from the LFCR.

Q. Please summarize your recommendations regarding the LFCR.

A. I recommend that the Commission recognize that the LFCR is a targeted decoupling mechanism that efficiently addresses issues related to fixed cost recovery from sales lost to EE and DG. As a decoupling mechanism the LFCR is designed to compensate UNS for these lost sales, while maintaining the price signals necessary to incent conservation. As a result, the LFCR is a better method for addressing lost fixed cost recovery than other rate design changes proposed by UNS.

In addition, the Company maintains sufficient flexibility in generation capacity procurement to reasonably account for EE and DG sales reductions while avoiding stranded costs. Therefore, generation related costs are not appropriately

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[134] *Id.* at 74:26–75.3.
[135] *Id.* at 75:7–11.
[136] UNS Electric, Inc., *2014 Integrated Resource Plan* 55 (Apr. 2014), *available at* https://www.uesaz.com/doc/planning/2014-UES-IRP.pdf.

classified as “lost fixed costs.” The Commission should reject UNS’s proposal to add generation related charges to the LFCR.

6 UNS has not adequately evaluated the impacts of its proposals

Q. Has UNS adequately evaluated the impacts of its proposed rate design changes for NEM customers?

A. No. UNS has not adequately evaluated the impacts of its rate design proposals. As I discuss in detail below, UNS has failed to sufficiently analyze (1) how its proposed rate design changes will impact NEM customers; (2) the costs of service and benefit/cost analyses related to its DG proposals, as required by Commission Rule 14-2-2305; (3) the regulatory compliance risks resulting from its proposals; and (4) the solar jobs created by DG in Arizona that the proposals may put at risk.

6.1 UNS did not reliably assess the impacts of its proposals on NEM customers

Q. Has UNS provided any information on the impact of its proposals on NEM customers?

A. Witness Dukes claims that he shows “how DG customers still save on their total electric bill” as a result of UNS’s proposals.[137] However, the analyses put forth in his testimony are not based on actual NEM customer data.

Q. What was the basis for UNS’s NEM customer impact assessments?

A. In the Direct Testimony of witness Dukes, UNS presents two tables that purport to show the average monthly electric bills for residential customers with electric usage levels of 500 kWh, 900 kWh, 1,200 kWh, and 1,500 kWh.[138] The data in

[137] Dukes Direct Test. at 5:4–5.
[138] *Id.* at 20–21, 28–29.

both of these tables were derived based on average full requirements customer load shapes with an engineering-based assessment of solar generation based on the assumption that customers will size their PV systems to offset 100% of annual energy requirements.[139] These tables were not based on actual NEM customer data.

Q. How many of UNS's NEM customers size their PV systems to offset 100% of load?

A. UNS has not provided sufficient information to answer that question. UNS was asked in discovery, "How many of the residential solar PV systems in UNS's territory are sized to yield zero excess kWh?"[140] UNS replied that "[t]he Company does not track that information."[141] Vote Solar further asked UNS for any data, analyses, or other documentation to support the statement in Mr. Tilghman's testimony that net metering encourages NEM customers to oversize their DG system.[142] UNS never provided any data, analyses, or other documentation to support these claims.[143]

Vote Solar also requested data, analyses, and other documentation in support of Mr. Tilghman's claim that "[m]ost customers attempt to generate between 90%-100% [of their connected load annually].[144] UNS replied that "[c]ustomer applications received by the Company validate the fact that most applications and system sizes are designed to provide a near net-zero home based on the customer's annual consumption."[145] The Company, however, declined to provide any actual data.

After repeated questioning from various parties, UNS has been unable to provide any evidence to support its assumption that the "typical" solar facility is sized to

[139] Dukes workpaper "RES Demand-DG_04-29-15_FINAL_v1.xlsx" (Ex. BK-2 at 54).
[140] UNS Resp. to TASC 1.34(a) (internal quotation marks omitted) (Ex. BK-2 at 47).
[141] *Id.*
[142] UNS Resp. to VS 2.15 & VS 3.18 (Ex. BK-2 at 6, 20).
[143] *Id.*
[144] UNS Resp. to VS 2.21 (Ex. BK-2 at 9).
[145] *Id.*

offset 100% of customer load. In addition, UNS has not provided actual data on the average bills of customers before and after going solar,[146] and the Company has not supplied a bill frequency analysis for NEM customers despite requests to do so.[147]

Q. What does this imply about UNS's assessment of the impact of its proposals on NEM customers?

A. Because I cannot verify UNS's claims that the "typical" NEM customer will offset 100% of load, there is no basis on which to evaluate the reasonableness of UNS's purported NEM customer impacts from the Company's rate design proposals. Even if this claim could be verified, it is likely that at least some level of diversity exists among the NEM customers. This diversity would also need to be understood to provide a reliable assessment of the impact of the proposals on NEM customers.

Q. Why is it important that UNS provide a reliable assessment of the impact of its proposals on NEM customers?

A. To ensure that a rate change is just and reasonable, utilities often develop an assessment of representative load data for customers impacted by a rate proposal in order to provide evidence that a new rate will not unfairly impact the utility's customers. UNS acknowledges this with the following statement: "To best determine the true impact on the customer and the Company revenues, we went to great lengths to determine the appropriate levels of billing determinants. It was essential that we had a complete understanding of the billing determinants as we modified provisions within the tariffs."[148] In addition, UNS states that "in developing these proposed modifications, a thorough analysis must be performed to best ensure that the impacts on the customer are understood and the proposals

[146] UNS Resp. to TASC 1.10 (Ex. BK-2 at 45).
[147] UNS Resp. to VS 1.04 (Ex. BK-2 at 1).
[148] Jones Direct Test. at 33:6–9.

are fair and equitable."[149] However, despite UNS's own assertions that it is essential to have a complete understanding of the billing determinants and that a thorough analysis must be performed to ensure proposals are fair, UNS's cost of service study does not separately analyze NEM customer billing determinants.

6.2 UNS did not provide the costs of service and benefit/cost analyses required by Commission Rule 14-2-2305

Q Can you summarize Commission Rule 14-2-2305?

A. Yes. While I am not a lawyer and am not offering a legal opinion, Commission Rule R14-2-2305 says that utilities must provide a cost of service study and benefit/cost analyses if they propose to increase the costs paid by NEM customers relative to similar non-NEM customers. Specifically, the rule states:

> "Net Metering charges shall be assessed on a nondiscriminatory basis. Any proposed charge that would increase a Net Metering Customer's costs beyond those of other customers with similar load characteristics or customers in the same rate class that the Net Metering Customer would qualify for if not participating in Net Metering shall be filed by the Electric Utility with the Commission for consideration and approval. <u>The charges shall be fully supported with cost of service studies and benefit/cost analyses. The Electric Utility shall have the burden of proof on any proposed charge</u>."[150]

Q. Has UNS supported its DG rate design proposals with an adequate cost of service study?

A. No. While UNS attempts to single out NEM customers for differential treatment compared to non-NEM customers, the Company's cost of service study does not analyze NEM customers as a separate group of customers from the residential and small commercial classes. As a result, the cost of service study does not adequately support any new or additional charges for NEM customers.

[149] *Id.* at 33:20–22.
[150] A.A.C. R14-2-2305 (emphasis added).

Q. Has UNS supported its DG rate design proposals with benefit/cost analyses?

A. No. UNS has not provided any assessment of the costs or benefits of its proposal. UNS has not even analyzed the billing impact of its proposals on NEM customers, not to mention the impact its proposals may have on DG adoption rates.[151] Furthermore, as discussed above, UNS has failed to conduct a benefit/cost analysis to support its proposal to modify the NEM tariff.

6.3 UNS did not evaluate how its proposals could create regulatory compliance risks

Q. What are the potential implications of UNS's proposals regarding DG rate design changes?

A. UNS has proposed far-reaching changes in DG rate design that have the potential to severely undermine the solar market in its territory. The recent experience with SRP clearly demonstrates that rate design changes can significantly impact solar adoption rates. If the Commission were to approve UNS's proposals to compensate customers for their DG exports at the Renewable Credit Rate and to impose a mandatory demand charge rate on NEM customers, growth of DG on the UNS system would most certainly be reduced. Indeed, it is possible that UNS's proposals may even put the utility's regulatory compliance at risk and result in significant additional costs for ratepayers.

Q. Why would UNS's regulatory compliance be at risk?

A. The RES regulations require that UNS generate a minimum of 15% of its energy from renewable resources by 2025, with an interim target of 6% in 2016.[152] The regulations additionally contain a distributed renewable energy requirement that requires UNS to meet 30% of its RES requirement with distributed renewable

[151] UNS Resp. to VS 2.09(a) (Ex. BK-2 at 4).
[152] A.A.C. R14-2-1804.

energy resources.[153] While it is clear that this proposal may have a significant impact on the rate of DG growth in UNS's territory, UNS has not analyzed how large that impact may be.[154] It has, however, forecasted the expected level of DG adoption without its proposed changes and has predicted that under the current NEM tariff structure, DG adoption would be expected to continue at the pace required to meet the RES targets.[155] This indicates that if the proposed NEM tariff changes were to impact DG adoption in UNS's territory, it may have difficulty meeting the RES targets. Of additional concern is the fact that in its most recent RES Implementation Plan filed on July 1, 2015, UNS indicated that it will be unable to meet the 2016 small commercial DG requirement under the RES and requested a waiver from the Commission.[156]

If UNS has difficulty meeting the DG requirement under the RES, it may have significant consequences for UNS ratepayers. In UNS's most recent IRP, the utility examined a scenario in which UNS achieves only about 50% of the EE and DG targets directed by the Commission.[157] In that scenario, UNS found that if EE and DG were to be significantly reduced, it would need to install additional combustion turbines in 2019 and 2024 to meet the additional load growth.[158] There would be a significant cost to ratepayers if UNS must pay for additional power plants because its customers install less DG as a result of the Company's proposals. The decision to allow these substantial changes to the current DG rate structure should not be taken lightly.

Q. Would other aspects of UNS's proposals create regulatory compliance risks?

A. Yes. As I discuss in detail below, UNS has proposed to significantly increase the fixed charges for residential and small commercial customers. These higher fixed

[153] A.A.C. R14-2-1805.
[154] UNS Resp. to VS 2.09 (Ex. BK-2 at 4).
[155] *See id.*
[156] UNS Electric, Inc., *2016 Renewable Energy Standard Implementation Plan* 6 (July 2015), *available at* http://images.edocket.azcc.gov/docketpdf/0000162403.pdf.
[157] *See* UNS IRP, *supra* note 136, at 221.
[158] *Id.*

charges can have far reaching environmental compliance impacts. For example, the Clean Power Plan ("CPP") will require reductions in carbon dioxide emissions from the electric power sector, and the cost of CPP compliance can be significantly impacted by rate design. In a recent paper from the Regulatory Assistance Project, the authors found that rate designs that increase fixed customer charges have the potential to significantly increase customer consumption levels.[159] Because utilities dispatch electric generating units based in part on variable operating costs, marginal generating units that would respond to increases in consumption are generally less efficient than the units that have already been dispatched. As a result, the authors point out that small changes in customer usage can produce larger-than-average changes in total emissions.[160] This implies that "a utility with a progressive rate design that moves to a high-fixed-charge rate design may experience a significant increase in generation and emissions, making compliance with the CPP more difficult."[161] UNS's proposal to reduce the number of residential tiers would likely have a similar impact.

6.4 UNS should consider solar jobs along with the Economic Development Rider

Q. Please describe the Economic Development Rider proposed by UNS.

A. UNS has proposed to offer a discounted rate to business customers with a projected peak demand of 1,000 kW or more, and a load factor of 75% or higher.[162] The rate discount would decline over a five year period beginning with a 20% discount in Year 1 and declining to 2.5% discount in Year 5.[163] The Economic Development Rider would be available for 5 years and enrollment

[159] Jim Lazar & Ken Colburn, Regulatory Assistance Project, *Rate Design as a Compliance Strategy for the EPA's Clean Power Plan* 2–3 (Nov. 2015), *available at* http://www.raponline.org/document/download/id/7842.
[160] *Id.* at 1.
[161] *Id.* at 3.
[162] Duke Direct Test. at 31:25–27.
[163] *Id.* at 32:23–24.

would be capped at 50 MW.[164] To qualify for the Economic Development Rider, a customer must qualify for at least one of two existing Arizona state tax programs.[165]

Q. What rationale does UNS give in support of its proposed Economic Development Rider?

A. UNS points out that its service territory has been slow to recover from the recession and has lost several large customers in the past few years.[166] UNS claims that the Economic Development Rider would put UNS's service territory in a better competitive position to attract and expand business load, which would be beneficial to the entire customer base and the State of Arizona.[167]

Q. Will the Economic Development Rider generate new jobs?

A. That is unclear. UNS has not performed any estimation of the number of jobs (if any) that the Economic Development Rider would be expected to generate.[168]

Q. Does the solar industry provide a significant number of jobs in Arizona?

A. Yes. As of November 2014, there were 9,170 solar workers employed in Arizona and with the vast potential for additional solar deployment it is expected that at least 3,000 new solar jobs could be created.[169]

Q. How should the Commission consider solar jobs in Arizona when it acts on UNS's proposals?

A. As the Commission considers the merits of an Economic Development Rider that would reduce fixed cost recovery from participating customers,[170] it should also

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[164] *Id.* at 32:2–4.
[165] *Id.* at 32:7–10.
[166] *Id.* at 30:17–19.
[167] *Id.* at 31:16–20.
[168] UNS Resp. to VS 2.03(b) (Ex. BK-2 at 3).
[169] Solar Found., *Arizona Solar Jobs Census 2014*, at 4–5 (Feb. 2015), *available at* http://www.thesolarfoundation.org/wp-content/uploads/2015/02/Arizona-Solar-Jobs-Census-2014.pdf.

consider the very real economic benefits provided by the Arizona solar industry. UNS's proposed changes to the NEM tariff have the potential to destroy the solar market in UNS's service territory, putting real solar jobs at risk.

7 UNS Claims It Needs To Modernize Its Rate Design, But Its Proposals Are Regressive

Q. How does UNS frame its rate design requests in terms of general rate policy?

A. UNS's application characterizes its proposals as necessary to "modernize" rate design.[171] The Company claims that "[i]n this proceeding, UNS Electric seeks approval for 21st century rates."[172]

Q. In your opinion, are UNS's proposals a step toward a modernized rate design?

A. No. UNS's proposal to double basic service charges for residential and small commercial customers and to reduce the number of residential tiers is not reflective of "modern" rate design. Instead, it reflects regressive actions that will undermine Commission policy.

7.1 UNS's request to increase fixed charges for residential and small commercial customers should be rejected

Q. Please describe UNS's proposal to increase fixed service charges.

A. UNS proposes to increase all monthly basic service charges "in a manner consistent with the results of the [Customer Cost of Service Study] and equitable fixed cost recovery."[173] UNS proposes to increase the residential fixed charge

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[170] UNS Resp. to VS 2.03(a) (Ex. BK-2 at 3).
[171] Application at 8:5.
[172] Hutchens Direct Test. at 3:16.
[173] Jones Direct Test. at 34:12–13.

from $10/month to $20/month[174] and the small commercial fixed charge from $14.50-$16.50/month to $30/month.[175] Current and proposed fixed charges for residential and small commercial customers are summarized in Table 3.

Table 3: Current and Proposed Fixed Charges – Residential and Small Commercial[176]

Cost Study	**Residential**	**Small Commercial**
Current Fixed Charge	$10.00	$14.50-$16.50
Proposed Fixed Charge	$20.00	$30.00

Q. What support does UNS give for its proposal?

A. UNS has completed a customer cost of service study ("CCOSS"), which includes an embedded cost study and a marginal cost study. UNS says "[t]he goal of the CCOSS is to determine fair cost allocation and rate design among the customer classes based on the principle of cost causation"[177] In developing the CCOSS, UNS classified utility costs into three basic categories: customer, demand, and energy.[178] UNS's approach to the CCOSS was similar to the approach used in the last general rate case, with one notable exception in the methodology for allocating distribution-related costs.

Q. What has UNS proposed for allocation of distribution-related costs?

A. UNS has proposed a significant change to the methodology for classifying distribution-related costs, which has inflated its estimates of customer-related costs. In the last rate case, UNS used the Basic Customer Method, basing customer costs on "metering, services, meter reading, customer service and

[174] *Id.* at 40:26–41.1.
[175] *Id.* at 43:14–16.
[176] *Id.* at 40:26–41.1, 43:14–16.
[177] *Id.* at 3:17–19.
[178] *Id.* at 17:21–22.

billing."[179] In its application, UNS has proposed to re-classify a significant amount of additional costs as customer-related through the Minimum System Method.

Q. What is the Minimum System Method and is it an appropriate method for classifying customer costs?

A. The Minimum System Method is an approach to utility cost classification that looks at the theoretical minimum demand of a customer and estimates the smallest size of infrastructure necessary to serve the theoretical minimum customer, including poles, cable, transformers, etc. Under the Minimum System Method, investments in the theoretical minimum sized infrastructure are allocated to the customer cost function. The Minimum System Method is not a new approach to utility cost classification. In fact, Professor Bonbright addressed this method in his seminal text, "Principles of Public Utility Rates" in 1961. Bonbright did not agree with the Minimum System Method for customer cost allocation, stating that "the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems to me clearly indefensible."[180]

This sentiment has been echoed directly by the Washington Utilities and Transportation Commission:

> "In this case, the only directive the Commission will give regarding future cost-of-service studies is to repeat its rejection of the inclusion of the costs of a minimum-sized distribution system among customer-related costs. As the Commission stated in previous orders, the minimum system method is likely to lead to the double allocation of costs to residential customers and over-allocation of costs to low-use customers. Costs such as meter reading, billing, the cost of meters and service drops, are properly attributable to the marginal cost of serving

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[179] Craig Jones Direct Testimony in UNS 2013 General Rate Case, Docket No. E-04204A-12-0504, at 16:26–27 (Dec. 31, 2012), *available at* http://images.edocket.azcc.gov/docketpdf/0000141155.pdf.

[180] James C. Bonbright, *Principles of Public Utility Rates* 348 (1961), *available at* http://media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf.

a single customer. The cost of a minimum-sized system is not. The parties should not use the minimum system approach in future studies."[181]

Because the Minimum System Method is not an appropriate means of allocating distribution related costs, the Commission should reject UNS's proposal to employ the Minimum System Method in this case. The Commission should instead require that UNS return to the Basic Customer Method approved in the last general rate case, which limits customer-related costs to metering, services, meter reading, customer service, and billing.

Q. What were the results of UNS's CCOSS with regard to residential and small commercial customer costs using the Minimum System Method?

A. Table 4 summarizes the results of UNS's embedded and marginal cost studies using the Minimum System Method.

Table 4: CCOSS Customer Cost Results using Minimum System Method[182]

Cost Study	Residential	Small Commercial
Marginal Customer Cost	$51.82	$102.03
Embedded Customer Cost	$14.00	$28.18

Q. How do UNS's CCOSS results inform the proposed basic service charges?

A. UNS described the relationship between the embedded cost study results, the marginal cost study results, and the proposed basic service charges as follows:

"The embedded cost of service study guides the allocation of revenues among the classes of service . . . . In order to fully evaluate the appropriate level of basic service charge, a marginal cost of service is required in order to support and reflect a valid price signal related to connecting customers. . . . Together, the embedded and marginal cost studies provide the Commission with the full picture as to how total revenues should be allocated across classes; and in turn, how

[181] *Wash. Utils. & Transp. Comm'n v. Puget Sound Power & Light Co.*, 3d Supplemental Order, Docket Nos. U-89-2688-T & U-89-2955-T, at 71 (WUTC Jan. 17, 1990), *available at* http://www.utc.wa.gov/_layouts/CasesPublicWebsite/GetDocument.ashx?docID=89&year=1989&docketNumber=892688.
[182] Jones Direct Test. at 30:5–7.

customer costs and the cost of connecting a customer should be set to send correct price signals to customers and to encourage economic use of the system."[183]

Q. How did UNS arrive at its proposal for a $20 residential customer charge and a $30 small commercial customer charge based on these results?

A. It appears that UNS ultimately used the results of the embedded cost study for both customer-related costs and demand-related costs as the foundation of its customer charge proposal. This is evidenced by the Company's assertion that its $20 residential basic service charge proposal represents 37% of the $54.46 in combined customer and demand related charges identified for the residential customer.[184]

Q. How was the $54.46 in combined customer and demand related charges derived, and what is UNS's rationale for its importance?

A. UNS states:

> "Historically, basic charges are limited to metering, meter-reading, service (service drop) to the specific customer, and customer service and billing. While these costs should be included in the basic service charge and may be used as the guide to what the basic service charge should be for classes with Demand Charges, they are not sufficient for classes without a Demand Charge."[185]

In support of this notion, UNS estimated the combined customer and demand related costs by adding together the $14.00 customer costs and $40.46 in demand costs from the embedded cost study to arrive at an estimate of $54.46 for residential customers.[186]

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[183] *Id.* at 30:24–31:8.
[184] *Id.* at 41:1–4.
[185] *Id.* at 37:5–9.
[186] While the $54.46 in total customer and demand costs identified by the UNS embedded cost study is similar to the marginal cost study result of $51.82, this similarity appears to be a coincidence.

Q. Does this estimated customer cost reflect the results of the Minimum System Method described earlier?

A. It does not. Despite an over-allocation of costs to the customer-related category, the Minimum System Method identified only $14.00 in embedded customer costs for residential customers. In support of its proposal, UNS also looks at the $40.46 its own methodology classified as unrelated to the customer function. UNS claims "it must collect approximately $54 per month from residential customers to recover all of the fixed costs associated with providing them with electric service."[187]

This approach is wholly inappropriate. UNS is seeking to over-allocate costs to the customer charge by mischaracterizing demand-related costs as fixed costs. Demand-related costs identified by the CCOSS should not be considered in the assessment of an appropriate basic service charge, regardless of whether the customer class in question is subject to a demand charge. UNS's own assessment of cost causation in the CCOSS allocates demand-related costs based on various measures of customer usage. Therefore, these costs are variable and not fixed. Basic service charges should be limited to customer-related costs identified using the Basic Customer Method.

Q. Have you developed an estimate of the embedded and marginal customer costs for residential and small commercial customers using the Basic Customer Method?

A. I have. To derive my estimate, I used the following methodology and calculations. In support of using the Minimum System Method, UNS developed an estimate of the proportion of distribution costs in FERC Accounts 364-368 that should be classified as customer-related.[188] UNS additionally assumed that a proportionate amount of operations and maintenance ("O&M") costs associated with these accounts should be customer-related, as well as a certain level of general plant

[187] Hutchens Direct Test. at 12:5–7.
[188] Jones Direct Test. at 22:1–4.

and administrative and general costs.[189] FERC Accounts 364-368 are associated with distribution system investments and are summarized in Table 5 below. Table 5 also shows the percent of costs by account that were allocated to customer costs in the current application and in the last approved rate case.

Table 5: Distribution Cost Allocation[190]

FERC Account	Description	Application Customer %	Last Rate Case Customer %
364	Poles Towers & Fixtures	60%	0%
365	Overhead Conductors & Devices	35%	0%
366	Underground Conduit	100%	0%
367	Underground Conductor	35%	0%
368	Line Transformers	60%	0%

Q. How did you develop your estimate of embedded and marginal costs using the Basic Customer Method?

A. I modified UNS's CCOSS to include the methodology the Company used in its last rate case for allocating FERC Accounts 364 through 368 and associated O&M, general plant, and administrative and general costs.[191] This allowed me to develop an estimate of the embedded and marginal customer costs under the Basic Customer Method that is consistent with the methodology employed in the last rate case. My results are summarized in Table 6 below.

Table 6: CCOSS Customer Cost Results using Basic Customer Method

Cost Study	Residential	Small Commercial
Marginal Customer Cost	$9.96	$12.48
Embedded Customer Cost	$7.50	$11.74

[189] *Id.* at 22:21–23:2.
[190] 2015 UNSE Schedule G – COSS.xlsx, tab Cust%; UNS Resp. to VS 3.14(b) (Ex. BK-2 at 16).
[191] I also discovered a spreadsheet error in UNS's original CCOSS related to meter cost allocation. UNS has acknowledged the error and the results shown in my testimony have corrected for this error.

As shown in Table 6, using the Basic Customer Method instead of the Minimum System Method results in a significantly lower estimate of customer-related costs. When the Basic Customer Method is employed, the marginal cost for residential and small commercial customers is estimated at $9.96 and $12.48, respectively. The embedded cost is estimated at $7.50 for residential customers and $11.74 for small commercial customers. These results demonstrate that the Minimum System Method significantly over-allocates costs to the customer function.

Q. Do the results of the CCOSS using the Basic Customer Method support UNS's proposed increases to the basic service charges for residential and small commercial customers?

A. They do not. In fact, an examination of the results of the CCOSS using the Basic Customer Method show that UNS's current basic service charges for residential and small commercial customers are reasonable and should therefore not be modified.

Q. Do UNS's proposed increased fixed charges present policy implications?

A. Yes. In addition to the very clear results of the CCOSS using the Basic Customer Method, the Commission should consider the policy implications of increasing fixed customer charges. In UNS's application, the Company states that "[m]odifying the rates to include a higher proportion of fixed costs in the monthly basic service charges will send customers the right price signals and provide additional support for the Company's efforts to promote EE and DG."[192] However, increasing fixed costs would be expected to decrease deployment of EE and DG due to the lower volumetric rate. What UNS appears to mean by this statement is that an increase to fixed charges would diminish the unrecovered fixed costs from EE and DG. As discussed above under the section on the LFCR, however, this argument is flawed. Any need for fixed cost recovery resulting from EE and DG growth is better addressed through the LFCR decoupling mechanism than through rate design.

[192] Jones Direct Test. at 37:21–24.

Increasing fixed charges as UNS proposes would have an impact beyond EE and DG. As discussed below, the Commission should take an active role in directing utilities to plan for the modern grid. This includes proactive planning on rate design structures that will enable efficient and cost-effective deployment of all distributed resources, not just EE and DG. Because higher fixed charges dampen the usage-based price signal, they interfere with price signals embedded in rates that motivate customers and DER providers to take action to reduce energy usage. A high fixed charge is not the "modern" rate design characterized by UNS, but rather a regressive blunt force instrument that is out of step with evolving technologies and the modern grid.

7.2 UNS's request to eliminate the third residential tier should be rejected

Q. What has UNS proposed regarding residential class rate tiers and what rationale was given for this proposal?

A. UNS has proposed elimination of the third tier in the standard residential rate.[193] UNS claims the third tier "adds no cost-based value to the rate class other than exacerbating the issues of fixed cost being inequitably recovered from the higher usage customers."[194] Interestingly, UNS has not proposed elimination of the third tier for standard small commercial rates despite the fact that it would seem to be subject to the same rationale.

Q. When was the inclining block structure put in place, and what was the Commission's reasoning for its approval?

A. An inclining block rate structure was first put into rates in 2008 with Decision No. 70628, which included the following Finding of Fact: "The inclining block rate structure, TOU rates and other rate design changes as set forth in the 2008 Settlement Agreement will promote energy conservation and beneficial load

[193] Dukes Direct Test. at 18:26–27.
[194] Jones Direct Test. at 42:5–6.

shifting."[195] Inclining block rates were never intended to be based on cost causation, but rather, were approved by the Commission for the express purpose of incenting conservation.

Q. Based on this procedural history, what is your recommendation regarding removal of the third residential tier?

A. Inclining block rates have been providing important conservation signals to UNS customers since 2008. The fact that inclining block rates result in proportionally higher charges for higher usage customers is no surprise. In fact, it is the intended outcome of the rate design measure. I recommend that the Commission reject UNS's proposal to remove the third tier in its standard residential rate.

8 The Commission should consider UNS's proposals in the context of the modern grid

Q. What is the modern grid and why is it important to consider?

A. With increasing availability of new technologies, the fundamental operation of the distribution grid is changing. In the evolution to the modern grid, the consumer is becoming a much more active participant in the production and consumption of their electricity through various DERs.[196] The modern grid will empower customers of all sizes to manage their energy usage and production in coordination with the utility for the benefit of both the consumer and the grid. Small customers may participate through third party aggregators, while larger and more sophisticated customers may participate directly. Transition to the modern grid is being driven by technology development. This is already happening and will continue to accelerate as prices for photovoltaic generators, distributed energy storage, electric vehicles, and other technologies continue to decrease.

[195] Decision No. 70628 at 46:22–23 (Dec. 1, 2008).
[196] *See* Steve Corneli & Steve Kihm, Lawrence Berkeley Nat'l Lab., *Electric Industry Structure and Regulatory Responses in a High Distributed Energy Resources Future* 1 (Nov. 2015), *available at* https://emp.lbl.gov/sites/all/files/lbnl-1003823.pdf.

It is crucial that the Commission recognizes this evolution in order to ensure that DERs can be deployed in a way that provides maximum grid support and improves reliability, while lowering overall costs and maximizing consumer benefits. In a recent report from Lawrence Berkeley National Laboratory ("LBNL"), economists found that "DERs will not only improve customers' energy costs, resilience and power quality, they can help utilities avoid risky capital expenditures and operate their systems more efficiently. By facilitating DERs, utilities can both lower their costs and increase the benefits they can offer customers who deploy DERs . . . ."[197]

Q. How should the Commission address the evolution to a modern grid?

A. The Commission has already begun to consider the evolution to the modern grid. In late 2013, Commissioner Burns opened Docket No. E-00000J-13-0375 entitled "In the matter of the Commission's Inquiry into Potential Impacts to the Current Utility Model Resulting from Innovation and Technological Developments in Generation and Delivery of Energy." The Commission has held many useful workshops in this docket, which have provided important information on emerging technologies. The Commission should build on this work to proactively look at how to develop DERs in the way that maximizes grid benefits and reliability, reduces costs, and facilitates customer choice. The Commission should require UNS and other Arizona utilities to prepare distributed resource plans that examine the potential for all types of DERs and identify the specific grid services that DERs can provide in order to produce the maximum benefit for both the grid and consumers. Distributed resource planning should be extensive and specific enough to identify the location and characteristics of DERs that would be most beneficial. The Commission should then require the utilities to develop sourcing plans to encourage deployment of DERs in the locations, quantities, and with the characteristics that best meet the needs of the grid and provide the maximum value for customers.

[197] *Id.*

According to the LBNL study:

> "DERs—with appropriate levels of coordination or virtual integration—can augment the capabilities of the distribution system and even reduce the amount of capital the utility must invest in it. Further, to the extent DER owners and hosts can realize additional value from DER ownership by, for example, providing frequency regulation or voltage support to the wholesale markets and the local distribution system, this leveraging of utility investment can be further enhanced. In effect, by substituting for utility investment, customer DERs can help keep utility revenue requirements within the bounds that increasingly price-sensitive customers will pay for."[198]

Q. Does UNS have any policies, plans, or incentives related to evolving grid technologies?

A. To date, UNS's grid evolution policies and planning have been limited. While the Company is planning to install meters capable of providing interval data for all customers and has implemented various EE programs, UNS does not have any policies or plans for how to integrate demand response, energy storage, or electric vehicles to maximize benefits for the grid and consumers.[199] As described above, while customers with electric vehicles can have large swings in energy requirements, UNS has no information on the current or forecast number of electric vehicles in its service territory.[200] The Company has also not performed any studies to determine the ability of its existing transformers to absorb increased load due to continued growth in popularity of electric vehicles.[201]

Q. Why should the Commission consider and address the evolution of the grid in this rate case?

A. UNS has recommended far-reaching changes to rates paid by customers who elect to install DG. The changes seek to make DG less cost effective for customers and will very likely slow down or stall the pace of DG deployment in UNS's service territory. DG is just one of many forms of DER that will be deployed by

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[198] *Id.* at 18 (footnotes omitted).
[199] UNS Resp. to VS 2.13 (Ex. BK-2 at 5).
[200] UNS Resp. to Staff 12.3 (Ex. BK-2 at 41).
[201] UNS Resp. to Staff 12.6 (Ex. BK-2 at 42).

customers or third parties on the UNS system. However, UNS has not considered the potentially game-changing impacts of technologies like electric vehicles, demand response, and energy storage. Instead, UNS has focused on rate measures to slow down the pace of consumer-driven DG deployment. By neglecting to plan for DERs and penalizing early technologies, UNS is ensuring that the inevitable evolution of the grid will be less efficient, will come at a higher cost, and will limit customer choice.

9 Conclusions and Recommendations

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

A. As I have shown in my testimony, UNS has not provided a sufficient basis to support any NEM-specific rate changes, and its various proposals designed to reduce DG growth are flawed and would likely violate the Commission's Rules. Contrary to UNS's claims, I have shown that NEM customers are not a significant contributor to UNS's retail sales reductions, they do not cause an inequitable cost shift, and there is no evidence that their DG systems cause substantial grid impacts in UNS's service territory. As a result, UNS's premise that DG causes "problems" that should be fixed with a new rate design is unfounded.

UNS's proposed solutions to the alleged "problems" created by DG are seriously flawed and would unjustly discriminate against NEM customers. First, the Company proposes to modify the NEM tariff to significantly reduce the credit NEM customers receive for excess generation. However, UNS has not demonstrated, or even analyzed, whether the reduced credit it proposes would appropriately approximate the value of solar DG. Moreover, the proposed credit rate would be extremely volatile and subject to gaming, and it would also likely violate the Commission's NEM rules. Next, UNS proposes to create a mandatory demand charge for NEM customers. This mandatory demand charge would effectively function as an additional fixed charge solely for NEM customers, as residential and small commercial customers lack the tools to effectively respond to demand charges. In UNS's last rate case, the Commission approved the LFCR to address any cost recovery issues created by DG and EE. This transparent mechanism better addresses UNS's concerns regarding DG than its other proposals, and there is no need for the flawed and discriminatory proposals regarding DG that UNS has asked the Commission to approve.

UNS also failed to adequately analyze how its proposals related to DG would impact NEM customers. The Company similarly failed to conduct the cost of service study and benefit/cost analyses required by the Commission Rules, and it did not consider the regulatory compliance risks created by its attempts to reduce DG. Moreover, while UNS has proposed an Economic Development Rider to increase economic growth in its service territory, it did not consider how its proposals would impact solar jobs.

Finally, UNS acknowledges the need to modernize its rate design in light of new technologies such as DG. However, its proposals are regressive and would not modernize the Company's rates. The Company proposes to significantly increase fixed charges for residential and small commercial customers based on an inappropriate methodology that over-estimated customer-related costs. I offer an alternative assessment of customer costs based on the embedded cost study and marginal cost study and find that the results of this assessment indicate that current levels of basic service charges for residential and small commercial customers are reasonable. Similarly, the company proposes to reduce its current inclining block structure for residential rates in a manner that would undermine conservation, EE, and DG, and it should therefore be rejected.

UNS's proposals reflect an outdated approach that is out of step with current trends toward grid modernization and the evolution of the grid to support consumer demands and advances in technology. Instead, UNS and the Commission should proactively consider how to utilize and incentivize EE, DG, and other DERs in a way that maximizes grid benefits, reduces costs, and facilitates customer choice.

Q. What are your recommendations for the Commission?

A. I recommend the following:

- The Commission should reject UNS's proposal to modify the existing NEM tariff and should not grant any waiver of the Commission's NEM rules.
- The Commission should reject UNS's proposal to create a mandatory demand charge for NEM customers.
- The Commission should reject UNS's proposal to include generation-related costs in the LFCR.
- The Commission should analyze how UNS's proposals will impact solar jobs when it considers the proposed Economic Development Rider.
- The Commission should require UNS to use the Basic Customer Method in its embedded and marginal costs studies in place of the Minimum System Method.
- The Commission should reject UNS's proposal to increase basic service charges for residential and small commercial customers.
- The Commission should reject UNS's proposal to modify the existing inclining block structure of residential rates.
- The Commission should begin a formal proceeding to address distributed resource planning.

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit BK-1

Statement of Qualifications

Briana Kobor
Program Director-DG Regulatory Policy, Vote Solar
360 22nd Street, Suite 730
Oakland, CA 94612
briana@votesolar.org

PROFESSIONAL EMPLOYMENT

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

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

Senior Associate, MRW & Associates
April 2007-August 2015

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

EDUCATION

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

PREPARED TESTIMONY

- CPUC Application A.14-06-014
  Testimony of Briana Kobor on behalf of the Coalition for Affordable Streetlights Concerning SCE's Proposed Street Light Rates. March 13, 2015.
- CPUC Application A.14-11-003
  Testimony of Briana Kobor on Behalf of the Utility Consumers' Action Network Concerning Sempra's Revenue Requirement Proposals for San Diego Gas & Electric and SoCalGas. May 15, 2015.

SELECTED PUBLICATIONS AND PRESENTATIONS

- Kobor, Briana. Rate Design to Support the Distributed Energy Future. Arizona Energy at the Crossroads Conference. November 2015.
- Monsen, Bill and Kobor, Briana. California Rules Worry Out-of-State Generators. Project Finance Newswire, Chadbourne & Parke. May 2012.
- McClary, Steven C., Heather L. Mehta, Robert B. Weisenmiller, Mark E. Fulmer and Briana S. Kobor (MRW & Associates). 2009. Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California. California Energy Commission. CEC-700-2009-009.
- Mehta, Heather, Kobor, Briana, & Weisenmiller, Robert. California Plans a Carbon Diet. Project Finance Newswire, Chadbourne & Parke. January 2009.

Exhibit BK-2

Discovery Responses Referenced in Testimony

VS 1.04

Please provide a bill frequency analysis for net metered customers based on the same strata and time frame as the response to VS Request 1-3 above.

RESPONSE:

Currently, the sales from net metering customers are booked in the total of their applicable standard offer tariff and not treated separately therefore all rate schedule bill frequencies as described in response to VS 1.03 also include net metering customers.

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

VS 1.05

Please provide the information requested below regarding the following statement by Mr. Dukes at page 12, lines 9–13 of his direct testimony: "Nearly one out of every four residential (Residential RES-01) bills issued by UNS Electric during the test year – 205,129 to be precise – reflected usage of 300 kWh or less. Because even a studio apartment with basic appliances and moderate usage would likely consume at least 400 kWh per month, these bills probably were generated by vacant homes, seasonal customers and DG customers."

a. Please indicate the basis for Mr. Dukes' statement.

b. Please indicate what proportion of these bills is attributed to vacant homes.

c. Please indicate what proportion of these bills is attributed to seasonal customers.

d. Please indicate what proportion of these bills is attributed to DG customers.

RESPONSE:

a. The basis of the claim that 205,129 residential test year bills reflected usage of 300 kWh or less can be found in the 2015 UNSE Schedule H-5 Unadjusted. The claim refers to the standard tariff residential customers (RES-01).

The 400 kWh portion of the statement is a rough estimate based on industry experience.

b.,c. The Company does not track whether the home that belongs to a bill is vacant or for what reason a home might be vacant.

d. Just under 5% of the 205,129 bills are attributed to residential DG customers.

RESPONDENT:

Greg Strang

WITNESS:

Dallas Dukes

UNS ELECTRIC INC.'S SUPPLEMENTAL RESPONSE TO VOTE SOLAR'S SECOND SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
September 29, 2015

VS 2.03

Please provide the information requested below regarding Mr. Dukes' statements about the Company's proposed Economic Development Rider on pages 30-32 of his direct testimony.

a. Will customers who take service under the proposed Economic Development Rider pay their entire share of fixed costs every year in which they take service under the Rider? If not, please quantify the proportion of fixed costs paid by Economic Development Rider customers in each year they receive the discount.

b. How many permanent full-time equivalent (FTE) jobs does the Company expect to be generated as a result of the proposed Economic Development Rider?

c. How will the Company know whether a customer that starts a new business or expands existing business operations in the Company's service territory did so because of the discounted electrics bills under the proposed Economic Development Rider?

d. Are there any safeguards in place to ensure that customers who qualify for the proposed Economic Development Rider would not start a new business or expand existing business operations in the Company's service territory without the Rider?

RESPONSE: September 28, 2015

a. Rider 13-Economic Development Rider specifies two schedules of discounts that will apply to a qualifying customer's total bill over a 5-year period, if the customer remains qualified for the entire period. The schedule of discounts applicable to a particular qualifying customer will depend on whether the customer's new or expanding business is classified as Economic Development or Economic Redevelopment as defined in the rider. To the extent that a qualifying customer's total bill contains fixed cost recovery, that fixed cost recovery will be reduced according to the discounts specified in Rider 13. The Company has not estimated any possible non-recovery of fixed costs.

b. The Company has not performed this estimation.

c.-d. The Company can never be 100% sure that a customer who starts a new business or expands existing business operations in the Company's service area is doing so solely because of the bill discounts in the proposed Rider 13-Economic Development Rider (EDR). UNS Electric's incentive for proposing Rider 13 is to (i) provide additional incentives for existing and prospective UNS Electric customers in order to support economic development in the Company's service territory, and (ii) provide for more efficient use of the current system and reduce fixed cost recovery for all customers. To that end, the Company can assure whether applicants for proposed Rider 13 meet the economic development criteria specified in the rider, which includes written documentation of qualification for either of two Arizona state tax credits designed to promote business recruitment and expansion.

RESPONDENT:

Rick Bachmeier

WITNESS:

Dallas Dukes

VS 2.09

Please provide forecasted distributed generation capacity (kW-AC) under each of the following scenarios for each year from 2015-2025:

a. The Commission approves UNS Electric's proposed modifications to the net metering tariff.

b. The Commission disapproves UNS Electric's proposed modifications to the net metering tariff and leaves the current tariff in place.

RESPONSE: September 28, 2015

UNS Electric is in the process of gathering this information and will provide it as soon as possible.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

SUPPLEMENTAL RESPONSE: September 29, 2015

a. The Company does not have access to distributed industry business plans or business models and is not able to make a reasonable forecast of DG capacity.

b. For the distributed generation forecast without proposed changes to the net metering tariff, please refer to page 182 of the Company's most recent integrated resource plan found at https://www.uesaz.com/doc/planning/2014-UES-IRP.pdf

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

VS 2.13

Does the Company currently have any policies, plans, or incentives addressing: (1) grid modernization, (2) electric vehicles, (3) demand response, (4) energy efficiency, (5) energy storage, and (6) advanced metering? If so, please describe and provide details on each of the Company's policies, plans, or incentives.

RESPONSE: September 28, 2015

UNS Electric is implementing different technologies that are generally considered grid modernization activities. These include the use of two way communications to distribution capacitor bank controllers and line reclosers. The plan is to implement these type of capabilities for all new or replacement activities involving this type of equipment. There are no policies or incentive associated with this plan.

UNS Electric does not have any policies, plans or incentives associated with electric vehicles.

UNS Electric does not have any policies, plans or incentives associated with demand response.

UNS Electric does have plans and incentives associated with energy efficiency. UNS Electric proposes an energy efficiency plan annually to the Commission for approval. UNS Electric implements the energy efficiency plan as approved by the Commission.

UNS Electric does not have any policies, plans or incentives associated with energy storage.

UNS Electric does not have any policies or incentives associated with advanced metering. UNS Electrics' plan is to install meters that provide interval data for all customers. The interval data will be stored in a meter data management system. The meter data management system is able to aggregate the intervals into billing determinants for any type of billing rate. The customer information system can use the billing determinants to create and issue the corresponding customer bill.

RESPONDENT:

Jim Taylor

WITNESS:

Jim Taylor

VS 2.15

On page 4, lines 25-26 of his direct testimony, Mr. Tilghman states that net metering "encourages customers to oversize their solar systems beyond their average load in order to 'bank' as many credits as possible for use later." Please provide data, analyses, and any other documentation to support that statement that are specific to the Company's service territory and that contemplate distributed generation at current penetration levels and at penetration levels projected in response to data requests VS 2-9(b) and VS 2-11(b). If applicable, please provide responses in executable electronic format with formulas and links intact.

RESPONSE: September 28, 2015

UNS Electric is in the process of gathering this information and will provide it as soon as possible.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

SUPPLEMENTAL RESPONSE: September 29, 2015

UNS Electric objects to this request as vague and ambiguous and unduly burdensome. Without waiving this objection, UNS Electric provides the following responses:

In its service area, the Company's experience is fact is that a typical solar facility is designed to be as close to "net zero" as possible, which also appears to be typical in other utility service areas. As such, with all solar generation being produced only during daylight hours and with a capacity factor of only (approximately) 25%, the maximum peak generation from the solar facility from a typical near net-zero facility is anywhere from 25-50% higher than the customer's average summer load; and significantly higher than the customer's average load during most of the year.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

VS 2.17

Please provide the information requested below regarding the following statement by Mr. Tilghman on page 5, lines 10-12 of his direct testimony: "Increased intermittent generation creates greater load imbalance and fluctuations in voltage and frequency requiring additional ancillary services."

a. Please provide data, analyses, and any other documentation to support this statement that are specific to the Company's service territory and that contemplate distributed generation at current penetration levels and at penetration levels projected in response to data requests VS 2-9(b) and VS 2-11(b). If applicable, please provide responses in executable electronic format with formulas and links intact.

b. Please quantify the level of additional ancillary services required on the Company's system due to current levels of distributed solar generation. Please answer separately for each of the following services: (1) load balancing, (2) frequency support, (3) voltage support, (4) spinning reserves, and (5) non-spinning reserves.

c. Please indicate the total annual capital cost expenditures incurred by the Company over the last five years related to provision of ancillary services that were incurred as a direct result of distributed generation at current penetration levels. Please answer separately for each of the following services: (1) load balancing, (2) frequency support, (3) voltage support, (4) spinning reserves, and (5) non-spinning reserves.

d. Please indicate the total levels of each type of ancillary service in the Company's territory. Please answer separately for each of the following services: (1) load balancing, (2) frequency support, (3) voltage support, (4) spinning reserves, and (5) non-spinning reserves.

e. Please indicate the total capital cost expenditures incurred by the Company over the last five years related to each type of ancillary service in the Company's territory. Please answer separately for each of the following services: (1) load balancing, (2) frequency support, (3) voltage support, (4) spinning reserves, and (5) non-spinning reserves.

RESPONSE: September 28, 2015

UNS Electric is in the process of gathering this information and will provide it as soon as possible.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

SUPPLEMENTAL RESPONSE: September 29, 2015

UNS Electric objects to this request as vague and ambiguous and unduly burdensome. Without waiving this objection, UNS Electric provides the following responses:

a. As noted in UNS Electric's response to VS 2.14, the Company relies on information provided by respected entities such as NERC, WECC, and others to provide supporting data for these statements.

b. Due to the fact that the entire service territory is controlled as one balancing authority (under TEP), it is impractical and overly burdensome to isolate and identify specific quantities of individual ancillary services or associated costs.

c. See UNS Electric's response to 2.17(b).

d. See UNS Electric's response to 2.17(b).

e. See UNS Electric's response to 2.17(b).

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

UNS ELECTRIC INC.'S SUPPLEMENTAL RESPONSE TO VOTE SOLAR'S SECOND SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
September 29, 2015

VS 2.21

Please provide the information requested below regarding the following statement by Mr. Tilghman on page 6, lines 5-6 of his direct testimony: "Most [net metering] customers attempt to generate between 90%-100% [of their connected load annually]."

a. Please provide data, analyses, and any other documentation to support this statement that are specific to the Company's service territory. If applicable, please provide responses in executable electronic format with formulas and links intact.

b. Please define "connected load" and the relationship between connected load and peak load for a customer.

RESPONSE: September 28, 2015

UNS Electric is in the process of gathering this information and will provide it as soon as possible.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

SUPPLEMENTAL RESPONSE: September 29, 2015

a. Customer applications received by the Company validate the fact that most applications and system sizes are designed to provide a near net-zero home based on the customer's annual consumption.

b. Connected load used in this context is the customer's annual consumption. The relationship between a customer's connected load and peak load varies by customer and cannot be "defined". A customer's peak load can be daily, seasonal, or annual and represents their instantaneous peak consumption.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

VS 2.24

On page 6, lines 16-19 of his direct testimony, Mr. Tilghman states: "Excess energy does not always 'flow to the next door neighbor' as is often quoted. During times of high export and low customer load, neighbors of exporting customers often have low usage as well, resulting in the energy flowing back up through the distribution system." Please provide data, analyses, and any other documentation to support any negative impacts resulting from "energy flowing back up through the distribution system" that are specific to the Company's service territory and that contemplate distributed generation at current penetration levels and at penetration levels projected in response to data requests VS 2-9(b) and VS 2-11(b). If applicable, please provide responses in executable electronic format with formulas and links intact.

RESPONSE: September 28, 2015

UNS Electric is in the process of gathering this information and will provide it as soon as possible.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

SUPPLEMENTAL RESPONSE: September 29, 2015

UNS Electric objects to this request as vague and ambiguous and unduly burdensome. Without waiving this objection, UNS Electric provides the following responses:

A number of circuits within both UNS Electric and TEP's systems have shown to have reverse current flow on at least one phase due to distributed generation. This is a result of random installations of customer sited distributed generation systems, resulting in unbalanced current flows on phases. This phenomenon is a relatively new issue that has been identified as a result of individual DG systems being connected single phase to a distribution system that was originally designed for one way power flow from the three phase system with equal loading among the phases. Unbalanced distributed generation between phases creates reverse power flows, which the system may see as a fault condition.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

VS 3.01

Please provide the information requested below regarding the following statement by Mr. Tilghman at page 7, lines 14–17 of his direct testimony: "The Renewable Credit Rate – currently proposed to be 5.84 cents per kWh – is equivalent to the most recent utility scale renewable energy purchased power agreement connected to the distribution system of UNS Electric's affiliate, TEP."

a. Please provide all data, analyses, and other documentation that were used to support this proposal.

b. Please indicate the type of utility scale renewable resource associated with the purchased power agreement referred to in the statement.

c. Please indicate the date of the purchased power agreement referred to in the statement.

d. Please indicate the capacity of the resource associated with the purchased power agreement referred to in the statement.

e. Please provide all pricing details of the purchased power agreement referred to in the statement. Please include detailed terms related to payments for energy, capacity, and other services, as well as any escalation terms.

f. Please provide the information requested in subparts (b) through (e) of this question for all renewable energy purchased power agreements signed by UNS and TEP in the last five years. For each agreement, please indicate whether the agreement was with UNS or TEP.

RESPONSE:

THE FILE LISTED BELOW CONTAINS COMPETITIVELY-SENSITIVE CONFIDENTIAL INFORMATION THAT IS ONLY BEING PROVIDED TO THE REQUESTING PARTY PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

a. Please see STF 2.038 Avalon Solar Facility-Competitively Sensitive Confidential.pdf, Bates Nos. UNSE\013366-013386, for the Avalon Solar Facility contract (Phase II).

b. The facility is a ground-mounted single-axis tracking PV system.

c. The agreement is dated December 17, 2014.

d. Expected facility capacity is 21.526 MW (DC).

e. Please refer to agreement. Contract price is fixed with no escalation and is all-inclusive for energy, capacity, and environmental attributes.

f. UNS has recently filed a PURPA solar agreement, which can be viewed publicly under Docket NO. E-04204A-15-0314, dated August 31, 2015 for a 70 MW(ac) single axis tracking facility priced at the company's calculated avoided cost for 25 years (see Exhibit E of contract). Contract is awaiting ACC approval.

The following is a list of new TEP contracts signed in the last 5 years (assignment of older contracts excluded):

(a.) 1.0452 MW (dc) DCI panel tracking facility, dated October 1, 2015. Contract Price $58.00 per MWh, fixed with no escalation and includes all energy, capacity, and environmental attributes.

(b.) 1.38 MW(dc) LCPV facility, dated March 23, 2013. Contract Price $108.75 per MWh plus lease and land adjustments, fixed with no escalation and includes all energy, capacity, and environmental attributes.

Additionally, TEP has utility scale solar projects connected to its EHV transmission system (non-distribution) that are single axis tracking PV facilities with all-inclusive fixed pricing (no escalation) that ranges from $68.30 per MWh for a 2013 project to $50.60 per MWh for a 2015 solar facility. Even though the most recent contract is lower than the value being proposed as the current market price, it is not being used at the equivalent utility scale market price due to the fact that it is connected to the Company's EHV system and not its distribution system.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

VS 3.03

Please provide the information requested below regarding the following statement by Mr. Jones at page 15, lines 15–17 of his direct testimony: "For distribution services, the cost of serving these partial requirements customers is typically the same or higher than it was when the customer was a full requirements customer."

a. How does Company define the term "typically" as used in this sentence?

b. Please provide an estimate of the average increase in distribution services costs when a customer elects to install distributed generation.

c. Footnote 4 states distributed generation customers "may require additional investments in the distribution system." Please indicate whether UNS has completed any additional investments in the distribution system due to partial requirements customers on its system. If the answer is yes, please provide the annual expenditures on such investments in each of the last 5 years.

RESPONSE:

a. In this instance, "typically" means…the cost of serving these partial requirements customers "normally" is the same or higher than it was when the customer was a full requirements customer.

b. The Company has not performed a specific study to determine what the additional distribution system cost increases are caused by connecting a partial requirements customer to the distribution system is precisely, but is certain that the added equipment, personnel time, training and energy needs will typically generate additional costs and burdens on the existing distribution system when compared to the costs associated with serving a full requirements customers. Items contributing to this additional costs include, but are not limited to: equipment and services necessary to provide ability to bi-directionally meter these generators and the related system controls needed to allow this type of usage, special disconnect equipment, voltage and power quality issues created by inverters, intermittency mitigation resources and necessary reserves, additional safety considerations and training, longer outage times due to back-feed onto the system from these distributed generation sources, dedicated customer service representatives and related training, additional requirements to modify weather and other load profile evaluations to address the intermittent loads, evaluation and accommodation of the impacts on the utility's system based on where the generator is located on the system, etc.

c. The Company has not attempted to track and assign all of the additional costs associated with the above impacts caused by the addition of these partial requirements customers, but is certain none of these services can be provided without additional costs.

RESPONDENT:

Rick Bachmeier / Craig Jones

WITNESS:

Craig Jones

UNS ELECTRIC INC.'S RESPONSE TO VOTE SOLAR'S THIRD SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
November 2, 2015

VS 3.08

Please provide the information requested below regarding the following statement by Mr. Jones at page 37, lines 21–24 of his direct testimony: "Modifying the rates to include a higher proportion of fixed costs in the monthly basic service charges will send customers the right price signals and provide additional support for the Company's efforts to promote EE and DG."

a. Please explain how increasing the monthly fixed charge will provide additional support for the Company's efforts to promote EE and DG.

b. Please describe the Company's current policies, plans, and incentives to promote EE and DG.

c. Please describe any future policies, plans, and incentives the Company plans to implement to promote EE and DG.

d. Has the Company evaluated how its proposed rate structure would impact customer demand for EE and DG?

e. Has the Company evaluated decoupling as a method of promoting both Company and consumer investments in EE and DG? If so, please describe how decoupling was considered and provide any supporting documentation.

RESPONSE:

a. More fixed costs being recovered through a fixed charge reduces the amount of fixed cost recovery lost due to the promotion of EE and DG.

b. Please refer to the Company's recent EE and REST implementation plans that have been docketed with an approved by the Commission.

c. Please refer to the Company's recent EE and REST implementation plans that have been docketed with and approved by the Commission.

d. The Company is not aware of any specific studies performed by the Company that would be responsive to this request. However, creating a three part rate will promote the use of equipment and systems that will reduce a customer's capacity needs instead of just offsetting volumetric needs. Offsetting volumetric needs only contributes to the reduction in fuel and purchased power, it does not reduce capacity needs. By creating a rate structure that promotes a reduction in capacity needs, the rate structure will provide a better end result to the promotion or EE and DG. By creating a rate structure that allows those customers who can modify their habits in a manner that truly helps the system, both the system (i.e. other customers) and the participating customer will benefit.

e. Yes. The LFCR was approved by the Commission in Company's last rate case. A portion of the costs not paid by the partial requirements customers is recovered through the LFCR by passing it on to the other customers, but not all of the lost fixed cost revenue is recovered through the LFCR. Improving cost recovery through rate design is a much better option.

RESPONDENT:

Craig Jones

WITNESS:

Craig Jones

VS 3.14

Please provide the following information regarding the tab entitled "Function Allocators" in 2015 UNSE Schedule G – COSS.xlsx:

a. Please indicate the source and underlying calculations and/or documentation to support the values presented in the following cells of the spreadsheet: I40, I41, J43, I44, I137, N137, I145, N145, I155, N155.

b. Please provide the equivalent functional allocators that were approved in the Company's last rate case in Docket E-04204A-12-0504.

c. To the extent any of the allocators presented in this case differ from the allocators approved with adoption of the Company's last rate case, please provide an explanation of the difference and the Company's rationale for updating the allocators.

RESPONSE:

a. The percentages included in the cells referenced above represent the results of the Marginal Cost Study approach used in this case as described in Craig Jones's direct testimony on pages 25 through 31.

b. Please see VS 3.14b.xlsx, which provides the function allocators used in the last Cost of Service Study and approved in the last rate case. The Excel file is <u>not</u> identified by Bates numbers.

c. The minimum system method used in this case was not developed or presented in the last approved case. Although it would have been preferred, the Company did not complete such a study in the last rate case. See response to STF 2.068 for a narrative and excel file discussing the allocations in COSS.

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

UNS ELECTRIC, INC.
ALLOCATION OF FUNCTIONS
INTERNAL WORKPAPER

				DEMAND						ENERGY			CUSTOMER				
FERC ACCT.		TOTAL COMPANY	DIRECT ASSIGNMENT	PRODUCTION	Blank	TRANSMISSION EXPENSE	Blank	DISTRIBUTION PRIMARY	DISTRIBUTION SECONDARY	FUEL	Cust	Blank	Customer Delivery	METER	BILLING & COLLECTIONS	METER READING	ALLOCATION

DEVELOPMENT OF RATE BASE FUNCTION ALLOCATORS

FERC	Plant in Service	TOTAL COMPANY	DIRECT ASSIGNMENT	PRODUCTION	Blank	TRANSMISSION EXPENSE	Blank	DISTRIBUTION PRIMARY	DISTRIBUTION SECONDARY	FUEL	Cust	Blank	Customer Delivery	METER	BILLING & COLLECTIONS	METER READING	ALLOCATION
301-303	**Total Intangible Plant**	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	PISXGENL
	Total Intangible Plant Excluding Direct Assignment	100.00%		21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	
	Total Steam Production																
310	Land & Land Rights	100.00%		100.00%													DPROD/DPRODMR
311	Structures & Improvements	100.00%		100.00%													DPROD/DPRODMR
312	Boiler Plant Equipment	100.00%		100.00%													DPROD/DPRODMR
313	Engines & Engine-Driven Generators	100.00%		100.00%													DPROD/DPRODMR
314	Turbogenerator Units	100.00%		100.00%													DPROD/DPRODMR/DPRC
315	Accessory Electric Equipment	100.00%		100.00%													DPROD/DPRODMR
316	Miscellaneous Power Plant Equipment	100.00%		100.00%													DPROD/DPRODMR
114	San Juan & Irvington Acquistion Adjustment	100.00%		100.00%													DPROD/DPRODMR
102	Electric Plant Purchased or Sold	100.00%		100.00%													DPROD/DPRODMR
	Other Production Plant																
340	Land & Land Rights	100.00%		100.00%													DPROD/DPRODMR
341	Structures & Improvements	100.00%		100.00%													DPROD/DPRODMR
342	Fuel Holders, Producers, & Accessories	100.00%		100.00%													DPROD/DPRODMR
343	Prime Movers	100.00%		100.00%													DPROD/DPRODMR
344	Generators	100.00%		100.00%													DPROD/DPRODMR
345	Accessory Electric Equipment	100.00%		100.00%													DPROD/DPRODMR
346	Miscellaneous Power Plant Equipment	100.00%		100.00%													DPROD/DPRODMR
	Transmission Non-EHV (138 KV & below) AD	100.00%				100.00%											DTNEHV
	Transmission EHV (345 KV & above) AD	100.00%				100.00%											DTEHV
	Distribution Plant																
360	Land & Rights	100.00%						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			DPIS
361	Structures & Improvements	100.00%						100.00%	0.00%				0.00%	0.00%			DPIS
362	Station Equipment	100.00%						100.00%	0.00%				0.00%	0.00%			DDISPSUB
364	Poles, Towers, & Fixtures	100.00%						100.00%	0.00%				0.00%	0.00%			DDISTPOL
365	Overhead Conductors & Devices	100.00%						100.00%	0.00%				0.00%	0.00%			DDISTPOL
366	Underground Conduit	100.00%							100.00%				0.00%	0.00%			DDISTSUL
367	Underground Conductors & Devices	100.00%							100.00%				0.00%	0.00%			DDISTSUL
368	Line Transformers	100.00%						100.00%	0.00%				0.00%	0.00%			DDISTSOT
369	Services	100.00%											100.00%				CUST
370	Meters	100.00%												100.00%			CMETERS
373	Street Lighting & Signal Systems	100.00%	0.00%						100.00%								DDISTLTG
374	Asset Retirement Obligation	100.00%							100.00%	0.00%	0.00%	0.00%	0.00%	0.00%			DPIS
389-398	**General Plant**	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	PISXGENL
	General Plant Excluding Direct Assign	100.00%		21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	
	Less: Accumulated Depreciation																
	Intangible Plant AD	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	PISXGENL
	Production Plant	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPRODPIS
	Other Production Plant	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPRODPIS
	Transmission Non-EHV (138 KV & below) AD	100.00%				100.00%											DTNEHV
	Transmission EHV (345 KV & above) AD	100.00%				100.00%											DTEHV
	Distribution Plant AD																
360	Land & Rights	100.00%						100.00%	0.00%				0.00%	0.00%			PLT360
361	Structures & Improvements	100.00%						100.00%	0.00%				0.00%	0.00%			PLT361
362	Station Equipment	100.00%						100.00%	0.00%				0.00%	0.00%			PLT362
364	Poles, Towers, & Fixtures	100.00%						100.00%	0.00%				0.00%	0.00%			PLT364
365	Overhead Conductors & Devices	100.00%						100.00%	0.00%				0.00%	0.00%			PLT365
366	Underground Conduit	100.00%						0.00%	100.00%				0.00%	0.00%			PLT366
367	Underground Conductors & Devices	100.00%						0.00%	100.00%				0.00%	0.00%			PLT367
368	Line Transformers	100.00%						100.00%	0.00%				0.00%	0.00%			PLT368
369	Services	100.00%						0.00%	0.00%				100.00%	0.00%			PLT369
370	Meters	100.00%						0.00%	0.00%				0.00%	100.00%			PLT370
373	Street Lighting & Signal Systems	100.00%	0.00%					0.00%	100.00%				0.00%	0.00%			PLT373
374	Asset Retirement Obligation	100.00%						0.00%	100.00%				0.00%	0.00%			DDISPSUB
	General Plant Accumulated Depreciation	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	PISXGENL
	Working Capital																
n/a	Cash Working Capital	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	OM
	Cash Working Capital Excluding Direct Assign	100.00%		21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	
151, 152	Fuel Inventory	100.00%		100.00%						0.00%							EPROD
154, 163	Materials & Supplies	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	TOTPIS
165	Prepayments	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	OM
	Less: Customer Contributions																
252	Customer Advances for Construction	100.00%	0.00%						100.00%								DCUSTADV
235	Customer Deposits	100.00%	0.00%						100.00%								DCUTDEP
230&253	Deferred Credits - Asset Retirement	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	77.39%	16.44%	0.00%	0.00%	0.00%	3.92%	2.26%	0.00%	0.00%	DISTPIS
	Other Rate Base																
105.0	Plant Held for Future Use - Transmission Plant (Non-EHV)						100.00%										DTNEHV
182.3	Regulatory Assets								100.00%								DISTPIS
254	Regulatory Liabilities								100.00%								DISTPIS
	Less: Accumulated Deferred Taxes (ADIT)																
190	ADIT	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	TOTPIS
282	ADIT - Other Property	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	TOTPIS
283	ADIT - Other	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	TOTPIS

DEVELOPMENT OF OPERATION & MAINTENANCE EXPENSE FUNCTION ALLOCATORS

FERC	Steam Power Generation Expense	TOTAL COMPANY	DIRECT ASSIGNMENT	PRODUCTION	Blank	TRANSMISSION EXPENSE	Blank	DISTRIBUTION PRIMARY	DISTRIBUTION SECONDARY	FUEL	Cust	Blank	Customer Delivery	METER	BILLING & COLLECTIONS	METER READING	ALLOCATION
500	Operation Supervision & Engineering	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
501	501-FUEL PPFAC ELIGIBLE	100.00%								100.00%							EFUEL
502	Steam Expenses	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD

UNS ELECTRIC, INC.
ALLOCATION OF FUNCTIONS
INTERNAL WORKPAPER

FERC ACCT.		TOTAL COMPANY	DIRECT ASSIGNMENT	DEMAND: PRODUCTION	DEMAND: Blank	DEMAND: TRANSMISSION EXPENSE	DEMAND: Blank	DEMAND: DISTRIBUTION PRIMARY	DEMAND: DISTRIBUTION SECONDARY	ENERGY: FUEL	ENERGY: Cust	ENERGY: Blank	CUSTOMER: Customer Delivery	CUSTOMER: METER	CUSTOMER: BILLING & COLLECTIONS	CUSTOMER: METER READING	ALLOCATION
505	Electric Expenses	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
506	Miscellaneous Steam Power Expenses	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
507	Rents	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
510	Maintenance Supervision & Engineering	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
511	Maintenance of Structures	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
512	Maintenance of Boiler Plant	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
513	Maintenance of Electric Plant	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
514	Maintenance Miscellaneous Steam Plant	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
411	FAS 143 Accretion Expense	100.00%		100.00%													DPROD
412	Gain on Sales of Emission Allowances	100.00%		100.00%													DPROD
	OTHER POWER GENERATION																
546	SUPERVISION & ENGINEERING	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
547	FUEL	100.00%								100.00%							EFUEL
551	SUPERVISION & ENGINEERING	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
552	MAINTENANCE OF STRUCTURES	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
553	GENERATING & ELECT PLT	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
554	MISC OTH POWER GEN PLT	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
557	OTHER EXPENSES	100.00%		100.00%	0.00%	0.00%	0.00%	0.00%									DPROD
	Other Power Supply Expense																
555	PURCHASED POWER																
	DEMAND CHARGES	100.00%		100.00%						0.00%							EPROD
	ENERGY CHARGES	100.00%								100.00%							EFUEL
	TOTAL PURCHASED POWER	0.00%															
556	SYS CONTRL & LOAD DISP	100.00%					100.00%										DPROD
557	OTHER EXPENSES	100.00%		100.00%													DPROD
560-573	PPFAC Transmission of Elec By Others	100.00%					0%			100%							DTNEHV
560-573	Transmission EXPENSE	100.00%				100%				0%							DTEHV
	Distribution Expense																
580	Operation Supervision & Engineering	100.00%						29.81%	43.33%				0.00%	26.86%			DISTPIS
581	Load Dispatching	100.00%						40.75%	59.25%				0.00%	0.00%			DISTPIS
582	Station Expenses	100.00%						100.00%	0.00%				0.00%	0.00%			DISTPIS
583	Overhead Line Expenses	100.00%						100.00%	0.00%				0.00%	0.00%			OHDIST
584	Underground Line Expenses	100.00%						0.00%	100.00%				0.00%	0.00%			UGDIST
585	Street Lighting & Signal System Expenses	100.00%	0%					0.00%	100.00%				0.00%	0.00%			DDISTLTG
586	Meter Expenses	100.00%						0.00%	0.00%				0%	100%			CMETERS
587	Customer Installations Expense	100.00%						0.00%	0.00%				0%	100%			CMETERS
588	Miscellaneous Distribution Expenses	100.00%						0.00%	100.00%				0.00%	0.00%			DISTPIS
589	Rents	100.00%						100.00%	0.00%				0.00%	0.00%			DISTPIS
590	Maintenance Supervision & Engineering	100.00%						96.00%	4.00%				0.00%	0.00%			DISTPIS
591	Maintenance of Structures	100.00%						100.00%	0.00%				0.00%	0.00%			DISTPIS
592	Maintenance of Station Equipment	100.00%						100.00%	0.00%				0.00%	0.00%			DISTPIS
593	Maintenance of Overhead Lines	100.00%						100.00%	0.00%				0.00%	0.00%			OHDIST
594	Maintenance of Underground Lines	100.00%						0.00%	100.00%				0.00%	0.00%			UGDIST
595	Maintenance of Line Transformers	100.00%						100.00%	0.00%				0.00%	0.00%			PLT368
596	Maintenance of Street Lighting & Signal Systems	100.00%	0%					0%	100%				0%	0%			DDISTLTG
597	Maintenance of Meters	100.00%						0%	0%				0%	100%			CMETERS
598	Maintenance of Miscellaneous Distribution Plant	100.00%						100.00%	0.00%				0.00%	0.00%			DISTPIS
407	Regulatory Asset Amortization	100.00%						0.00%	100.00%				0.00%	0.00%			DISTPIS
	Customer Account Expense																
901	Supervision	100.00%							0%	0%	0%	0%	0%	0%	73%	27%	CACCT
902	Meter Reading Expenses	100.00%														100%	CREAD
903	Customer Records & Collection Expenses	100.00%													100%		CBILLCOL
904	Uncollectible Accounts	100.00%							100%			0%					dUNCOL
905	Miscellaneous Customer Accounts Expenses	100.00%							0%	0%	0%	0%	0%	0%	73%	27%	ECUSINFO
907	Supervision	100.00%							0%	0%	0%	0%	0%	0%	73%	27%	ECUSINFO
908	Customer Assistance Expenses	100.00%							0%	0%	0%	0%	0%	0%	73%	27%	ECUSINFO
909	Informational and Instructional Advertising Expenses	100.00%							0%	0%	0%	0%	0%	0%	73%	27%	ECUSINFO
910	Miscellaneous Customer Service & Informational Expe	100.00%							0%	0%	0%	0%	0%	0%	73%	27%	DISTPIS
	Administrative and General Expense	100.00%	0.00%	11.14%	0.00%		0.00%	24.48%	19.65%				0.00%	8.56%	26.39%	9.78%	OMXF
	Depreciation and Amortization																
301-303	Total Intangible Plant Depreciation Expense	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	PISXGENL
	Production	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	DPRODP
	PPFAC Transmission of Elec By Others	0.00%					0.00%										DTNEHVP
	Transmission EXPENSE	100.00%				100.00%											DTEHVP
	Distribution Plant Depreciation Expense																
360	Land & Rights	100.00%						100.00%	0.00%				0.00%	0.00%			PLT360
361	Structures & Improvements	100.00%						100.00%	0.00%				0.00%	0.00%			PLT361
362	Station Equipment	100.00%						100.00%	0.00%				0.00%	0.00%			PLT362
364	Poles, Towers, & Fixtures	100.00%						100.00%	0.00%				0.00%	0.00%			PLT364
365	Overhead Conductors & Devices	100.00%						100.00%	0.00%				0.00%	0.00%			PLT365
366	Underground Conduit	100.00%						0.00%	100.00%				0.00%	0.00%			PLT366
367	Underground Conductors & Devices	100.00%						0.00%	100.00%				0.00%	0.00%			PLT367
368	Line Transformers	100.00%						100.00%	0.00%				0.00%	0.00%			PLT368
369	Services	100.00%						0.00%	0.00%				100.00%	0.00%			PLT369
370	Meters	100.00%						0.00%	0.00%				0.00%	100.00%			PLT370
373	Street Lighting & Signal Systems	100.00%	0.00%					0.00%	100.00%				0.00%	0.00%			PLT373
374	Asset Retirement Obligation	100.00%						0.00%	100.00%				0.00%	0.00%			PLT374
389-398	**General Plant Depreciation Expense**	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%				3.08%	1.78%			PISXGENL
	Taxes Other Than Income Taxes																
408	Property Tax - Production	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	DPROD
408	Property Tax - Transmission (Non-EHV)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	DTEHV
408	Property Tax - Transmission (EHV)	100.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	DTNEHV
408	Property Tax - Distribution	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	77.39%	16.44%	0.00%	0.00%	0.00%	3.92%	2.26%	0.00%	0.00%	DISTPIS
408	Property Tax - General	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	GENLPIS
408	Business Activity Tax - Generation	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	DPROD
408	Business Activity Tax - Transmission	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	DTNEHV
408	Other (Including Payroll Taxes)	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	TOTPIS
431	Customer Deposit Interest Expense	100.00%	0%						100%	0.00%	0.00%						CUSTDEP

UNS ELECTRIC, INC.
ALLOCATION OF FUNCTIONS
INTERNAL WORKPAPER

FERC ACCT.		TOTAL COMPANY	DIRECT ASSIGNMENT	DEMAND PRODUCTION	DEMAND Blank	DEMAND TRANSMISSION EXPENSE	DEMAND Blank	DEMAND DISTRIBUTION PRIMARY	DEMAND DISTRIBUTION SECONDARY	ENERGY FUEL	ENERGY Cust	ENERGY Blank	CUSTOMER Customer Delivery	CUSTOMER METER	CUSTOMER BILLING & COLLECTIONS	CUSTOMER METER READING	ALLOCATION
	Income Taxes																
409	Current Income Tax - State & Federal	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	PLANT
410	Deferred IT - Federal & State (debits)	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	PLANT
411	Deferred IT - Federal & State (credits)	100.00%	0.00%	21.31%	0.00%	0.00%	0.00%	60.90%	12.93%	0.00%	0.00%	0.00%	3.08%	1.78%	0.00%	0.00%	PLANT

VS 3.18

In response to VS 2.15, the Company stated: "In its service area, the Company's experience . . . is that a typical solar facility is designed to be as close to 'net zero' as possible, which also appears to be typical in other utility service areas." Please provide any available data, analyses, or other documentation to support this assertion. If possible, please provide data from the Company's Customer Care and Billing system.

RESPONSE:

The Company reviews all contracts as they are received, and as part of the review process, verifies that the system size is appropriate based on the customer's usage. As such, the Company typically sees solar system size designed to approximate the customer's annual consumption. The Company is also well aware that promotional materials and sales presentations by solar leasing companies are presented promoting net (or near) zero consumption in order to "eliminate you electric bill".

Providing all customers' data to show this premise would be unduly burdensome and would require not only the download of all NEM customers' data, but the calculation of total customer load versus production. This data is not readily available from the Company's CC&B system and would require manual calculation of each customer's data. As such, the Company objects to providing this data.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

VS 3.21

Please provide the information requested below regarding the Company's response to VS 2.24:

a. Please provide the number of circuits in each of UNS's and TEP's systems that have shown to have reverse power flow.

b. For each circuit identified, please indicate the date that circuit was identified as having reverse power flow.

c. For each circuit identified, please indicate the circuit capacity rating and the total capacity of installed distributed generation on that circuit (kW-AC).

RESPONSE:

UNS Electric objects to this request because the Company does not possess the information requested in the form it is requested and producing it in that form would be unduly burdensome and time consuming.

There are thousands of individual circuits from shared transformers to distribution feeders to substations that would require specific monitoring equipment to provide this information. The Company has found, that during either routine or specific testing, times when energy flow has been reversed. The Company does not; however, have equipment installed on all circuits that monitor and store this information.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

VS 3.24

Please provide the information requested below regarding the Company's Response to Staff 2.035:

a. Please indicate the number of distribution circuits that have been selected for SynerGEE software analysis.

b. Please indicate why these circuits were selected.

c. Please describe any plans to expand SynerGEE software analysis to additional circuits, including the criteria for selection of additional circuits.

d. Please identify the number of circuits in which SynerGEE powerflow software analysis indicated PV generation would have an impact to operations.

e. Please define "impact to operations" as used in this response.

f. Please describe, and to the extent possible quantify, any impact on operations identified in response to VS 3.25(d).

RESPONSE:

a. SynerGEE Powerflow software is used to model all Company circuits when required

b. Generation Interconnection requests, system reinforcement projects, capacitor placement studies, customer voltage complaints.

c. See (a) above

d. Three PV generation interconnection studies done with SynerGEE power flow software indicated existing distribution facilities could not support the proposed generation source, and would therefore have an impact on operations.

e. Impact to operations in this context refers to any contribution from the proposed generation source that negatively affects operations. Power flow studies associated with distributed generation interconnection requests include analysis of steady-state voltage, voltage flicker, and fault current with and without the proposed generation source.

f. There is no section (d) to question VS 3.25.

RESPONDENT:

Chris Lindsey

WITNESS:

Carmine Tilghman

UNS ELECTRIC INC.'S RESPONSE TO VOTE SOLAR'S THIRD SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
November 2, 2015

VS 3.34

Please provide information on the number of residential customers in the Company's service area with evaporative cooling and the number with refrigerated AC. If available, please provide average load profiles for these two customer types.

RESPONSE:

A 2010 study by Navigant Consultant provided the following breakdown of air conditioning system types for UNS Electric:

Central AC: 33%

Central Heat Pumps: 37%

Evaporative (Swamp) Cooler: 26%

Room A/C: 2%

Other: 2%

Source: Navigant Consulting, May 2011, "Demand-side Management (DSM) 2010 Targeted Baseline Study for Tucson Electric Power, Unisource Electric and Unisource Gas."

The Company does not have more recent data nor load profiles for these customer types.

RESPONDENT:

Sandra Holland

WITNESS:

Craig Jones

VS 4.4

Please provide the information requested below regarding the Company's response to VS 3.24:

a. In response to VS 3.24(a), the Company stated that "SynerGEE Powerflow software is used to model all Company circuits when required." Please indicate the number of circuits that have required modeling with SynerGEE Powerflow software.

b. In response to VS 3.24(d), the Company stated: "Three PV generation interconnection studies done with SynerGEE power flow software indicated existing distribution facilities could not support the proposed generation source, and would therefore have an impact on operations." How many PV interconnection studies have been done overall with SynerGEE power flow software?

c. The sub question number referenced in VS 3.24(f) was incorrect. Please describe, and to the extent possible quantify, any impact on operations identified in response to VS 3.24(d).

RESPONSE:

a. SynerGEE Powerflow software is the current tool used by the Company to model power flow on the distribution system. 18 circuits in Santa Cruz County and 12 circuits in Mohave County have been modeled using SynerGEE Powerflow software.

b. SynerGEE Powerflow software is used for both UNS Electric and Tucson Electric Power. Seven (7) PV interconnection studies have been completed with SynerGEE Powerflow software; two (2) for UNS Electric and five (5) for Tucson Electric Power.

c. Two (2) interconnection studies identified that the addition of generation would overload existing Company feeder conductors. For these two instances, upgrading the existing overhead feeder conductor was identified as a possible solution for supporting the proposed generation facilities.

   One (1) interconnection study identified that the addition of generation would create high-voltage and therefore violate the operating voltage criteria. Power factor correction at the generation facility was found to mitigate the problem.

RESPONDENT:

Christopher Lindsey

WITNESS:

Carmine Tilghman

STF 2.017

Retail Sales: Please provide in an Excel worksheet a summary of the impact (by month) of DG (by type) in UNS Electric's service area since January 2006 to the present. Provide the number of installations, total annual kWh (generated, used on-site and/or sold to the Company) and the peak load reductions from DG installations. Also please provide each of the Company's various forecasts for DG over that same period.

RESPONSE:

UNS Electric has data from the beginning of 2008 for DG systems. The Company does not track peak load reductions from DG installations, or conduct forecasts for DG installs.

Please see **STF 2.017.xlsx** for summary data. The Excel file is not identified by Bates numbers.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

Number of Installations by Month

		Residential		Non-Residential	
Year	Month	Total PV Installations	Total Wind Installations	Total PV Installations	Total Wind Installations
2008	January	0	0	0	0
	February	0	0	0	0
	March	0	0	0	0
	April	0	0	0	0
	May	0	0	0	0
	June	0	0	0	0
	July	2	0	0	0
	August	3	6	1	0
	September	2	2	0	0
	October	2	6	0	0
	November	2	1	0	0
	December	2	6	0	0
		13	**21**	**1**	**0**
2009	January	9	3	0	2
	February	9	3	0	0
	March	6	2	0	0
	April	13	4	0	1
	May	6	7	0	1
	June	12	17	0	0
	July	3	2	0	0
	August	11	6	2	0
	September	5	0	0	0
	October	26	12	0	0
	November	16	4	0	0
	December	16	7	3	0
		132	**67**	**3**	**4**
2010	January	0	24	0	0
	February	0	0	0	0
	March	18	0	1	0
	April	23	2	0	0
	May	25	0	1	0
	June	22	0	5	0
	July	25	0	1	0
	August	20	0	6	0
	September	13	1	0	0
	October	11	0	4	0
	November	13	2	0	0
	December	11	0	0	0
		181	**29**	**18**	**0**
2011	January	16	1	15	0
	February	9	1	4	0
	March	20	1	0	0
	April	22	0	0	0
	May	17	0	3	0
	June	9	0	2	0
	July	9	0	1	0
	August	19	1	4	0
	September	11	0	1	0
	October	25	0	2	0
	November	25	1	3	0
	December	21	0	7	0
		203	**5**	**42**	**0**
2012	January	20	0	2	0
	February	28	0	5	0
	March	39	0	2	0
	April	19	0	0	0
	May	26	0	3	0
	June	34	0	4	0
	July	20	0	2	0

Annual Production (kWH)

Residential	2008	2009	2010	2011	2012	2013	2014
PV	497,104	1,083,000	2,968,853	5,750,367	9,793,168	12,502,033	14,843,105
Wind	10,476	113,302	273,614	232,437	206,264	192,032	168,621
Non-Residential							
PV	24,856	96,904	329,366	1,356,949	6,344,477	10,157,204	9,752,817
Wind	1,405	8,915	8,354	9,626	6,216	8,124	6,112

Annual Overproduction Delivered Back to Company (Kilowatt Buyback Hours or KBH)

	2008	2009	2010	2011	2012	2013	2014
Residential	*	503,257	1,771,653	3,211,545	5,363,777	7,019,888	9,224,548
Non-Residential	*	17,722	163,303	679,300	1,708,087	3,105,456	4,252,135

*No Data Available for 2008 and prior.

	August	16	0		1	0
	September	40	0		2	0
	October	24	0		6	0
	November	3	0		3	0
	December	2	0		4	0
		271	**0**		**34**	**0**
2013	January	1	0		1	0
	February	0	0		3	0
	March	14	0		1	0
	April	13	0		0	0
	May	7	0		0	0
	June	12	0		0	0
	July	6	0		2	0
	August	19	0		2	0
	September	6	0		1	0
	October	10	0		1	0
	November	9	0		2	0
	December	11	0		2	0
		108	**0**		**15**	**0**
2014	January	35	0		1	0
	February	19	0		0	0
	March	25	0		0	0
	April	21	0		2	0
	May	16	0		0	0
	June	32	0		1	0
	July	25	0		0	0
	August	22	0		0	0
	September	19	0		0	0
	October	29	0		0	0
	November	35	0		1	0
	December	50	0		5	0
		328	**0**		**10**	**0**
2015	January	47	0		0	0
	February	24	0		1	0
	March	37	0		2	0
	April	17	0		0	0
	May	27	0		0	0
	June	47	0		0	0
	July	29	0		2	0
		228	**0**		**5**	**0**

STF 2.031

Renewable Resources: Please provide a narrative discussing how the Company forecasts short term (daily and hourly) PV generation. [Tilghman 4:18]

RESPONSE:

The Company utilizes a long standing relationship with the UA to forecast short-term (daily and hourly) PV generation by employing renewable power forecasts they have created. These forecasts include a number of forecasting technologies. These technologies include the use of numerical weather models, which enable us to forecast utility solar and DG solar for up to 10 days, satellite imagery analysis, which enables us to forecast utility and DG solar power generation for up to three hours, analysis of real-time utility and DG data, and a network of irradiance sensors, which enables the forecasting of utility and DG solar power generation for up to 120 minutes. Each of which will be discussed in further detail, below.

The Numerical Weather Prediction models make up the basis for the solar forecasts and allow us to forecast up to 10 days out. These models apply a numerical representation of weather affecting land and atmospheric processes. The specific model the Company uses is a southwestern United States specific Weather Research and Forecast ("WRF") model. This model was customized by the UA to create more accurate forecasts for the Desert Southwest. A specific modification to the model includes the running of the model at a higher resolution, in order to capture smaller scale weather phenomena, such as terrain induced winds, clouds, and monsoonal thunderstorms. This particular model is usually run by the UA around eight times a day and is initialized, every time it's run, with different data. Single model runs are highly unlikely to produce accurate forecasts every time; therefore, multiple model runs allow us to capture more in the forecasts. If a certain model run missed a weather event and we decided to utilize that model run, our forecast would be blaringly inaccurate. Having multiple model runs allows us to see the different events each model is forecasting and determine the most accurate forecast. The models are initialized by using observed data from weather balloons, surface weather stations, aircraft, and weather satellites. The renewable power forecasts are based on the 12 most recent weather forecasts.

The forecasting of short-term variability (up to three hours) is done by utilizing satellite image processing, which is the use of visible and infrared channels of the GOES satellite imagery to determine the irradiance that makes it to the ground. The irradiance calculation is combined with the PV power plant's clear sky expectation, which is a satellite production estimate. Real-time estimates of behind-the-meter generation can be determined from these calculations. Modeled wind speeds at the estimated cloud height are used to propagate the satellite-derived irradiance map forward to come up with the irradiance or PV power forecast.

A network of PV systems and irradiance sensors allow us to forecast PV power for up to 120 minutes. PV output, from the Company's utility-scale systems and 20 residential systems, is used as a proxy for irradiance. The UA also receives real-time production data, which is sent every two seconds to 15 minutes, from rooftop systems' data loggers from a local PV installer. Custom irradiance sensors, developed by the UA, that communicate by means of cellular modems are also used and send one-second resolution data every 60 seconds. Deviations from the clear sky profiles, which were created for each of the sensors by using filtered historical data, are interpreted and determined to be clouds or not. The clearness index (ratio of measured power to clear sky power) is calculated for each sensor. An interpolated clearness map across the forecasting domain is, then, created. The weather models' predicted wind velocities at their respective cloud heights determine the speed, direction, and uncertainty of the clearness map propagation. The resulting forecasted PV power can, then, be determined from the propagated clearness map.

The Company is also able to input information regarding any solar power plant outages into the forecast model created by the UA. By doing this, the forecast will change to account for the lack of availability during a given outage.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

STF 2.033

Renewable Resources: Please provide a narrative discussing how the Company has either implemented and/or researched the use of metering at individual PV connections (upstream of the utility meter) to monitor PV generation at the source. [Tilghman 5:15]

RESPONSE:

The Company requires that a meter be installed at the output of all DG sources for the collection of generation production data. For systems above 300kWac, the Company, at the customer's expense, installs more advanced metering equipment to obtain real-time production data for operations purposes. This data is collected and aggregated with other systems above 300kWac to better monitor the intermittent production of these generators. The data obtained from the larger systems is also used to approximate the production for the other smaller customer-owned distributed generators that do not provide real-time production data to Operations.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

STF 2.035

Renewable Resources: Please provide a narrative discussing how the Company models PV generation at the feeder level. [Tilghman 2:15]

RESPONSE:

The Company utilizes SynerGEE Electric powerflow software to model PV generation on the distribution system. The SynerGEE software has inverter-based generation models that can be added to a selected distribution circuit for analysis. Powerflow simulations are then run for peak feeder loading and minimum daytime feeder loading with and without the generation source to determine if the PV generation will have impact to operations

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

STF 2.079

Cost of Service: Please provide any studies, investigations, analyses or reviews performed by or for the Company that establishes the return of the residential and/or small commercial *subclasses* using distributed generation. If the Company has not performed these studies please explain why not. [Jones 15:7]

RESPONSE:

The Company does not currently look at DG/ net metering customers as a sub-class in the COSS nor are their billing determinants or revenues booked separately from standard offer service – something that will be reviewed prior to the next rate case.

The Company has looked at revenue recovery from a full requirement customer vs. a DG/net metering customer with 100% PV offset on an annual basis. See UNS Electric's supplemental response to UDR 1.001 dated July 30, 2015, specifically files RES Demand-DG_04-29-15_FINAL_v1.xlsx and SGS Demand-DG_04-29-15_FINAL_v1.xlsx. (The referenced files can be accessed in UNS Electric's electronic data room under Data Requests\Uniform Data Requests\Attachments - 1st Set\UDR 1.001\Workpapers – Testimony\Dallas Dukes.)

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

UNS ELECTRIC INC.'S RESPONSE TO STAFF'S SECOND SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-15-0142 August 31, 2015

STF 2.119

LFCR: Please provide a recalculation of the LFCR for the previous year demonstrating the impact of customer charges at the levels proposed by the Company and at 50% of the increase proposed by the Company. [Jones 41:7]

RESPONSE:

Please refer to **STF 2.119 LFCR Calculations.xlsx**. If the Company's proposed basic service charges were in place, the Company estimates that the LFCR would decrease by approximately $509,000 with respect to the Company's 2015 LFCR filing. This is because an increase to the basic service charge would result in a decrease to the volumetric energy delivery charges, if everything else is held constant. Using 50% of the proposed changes to the basic service charges, the Company estimates that the LFCR would decrease by approximately $255,000.

RESPONDENT:

Annie Trostle

WITNESS:

Craig Jones

UNS ELECTRIC INC.'S RESPONSE TO STAFF'S NINTH SET OF DATA REQUESTS
REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
September 10, 2015

STF 9.2

Please provide UNSE's customer count, usage per customer, and total mWh sales historical data by customer class for at least the past 10 years preferably both graphed and tabular.

RESPONSE:

Please see **STF 9.2.xlsx** for the requested information. The Excel file is not identified by Bates numbers.

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

Date	Total Residential	Total Commercial	Total Industrial	Total Mining	Total Other	Total
9/1/03	77,087,194	54,358,426	6,483,458	0	190,615	138,119,693
10/1/03	56,555,756	49,390,907	7,734,186	0	226,194	113,907,043
11/1/03	41,535,252	46,178,020	8,314,663	0	227,612	96,255,547
12/1/03	50,061,412	47,241,510	8,858,683	0	265,010	106,426,615
1/1/04	55,782,100	45,528,992	8,252,485	0	263,630	109,827,207
2/1/04	49,285,081	44,592,643	8,733,509	0	253,450	102,864,683
3/1/04	47,720,293	47,241,196	9,200,447	0	259,786	104,421,722
4/1/04	40,839,608	48,202,637	9,049,712	0	237,957	98,329,914
5/1/04	52,270,017	57,088,170	9,612,903	0	258,328	119,229,418
6/1/04	45,765,827	76,235,309	17,160,008	0	402,852	139,563,996
7/1/04	90,530,360	64,950,690	7,015,260	0	227,292	162,723,602
8/1/04	89,824,899	58,310,515	16,418,957	0	214,400	164,768,771
9/1/04	65,338,318	52,876,904	12,323,018	0	212,888	130,751,128
10/1/04	45,772,089	48,846,894	12,347,010	0	276,556	107,242,549
11/1/04	43,392,275	46,284,243	12,851,830	0	278,583	102,806,931
12/1/04	62,036,089	54,791,203	20,404,600	0	276,296	137,508,188
1/1/05	59,630,892	43,042,248	12,282,479	0	275,951	115,231,570
2/1/05	43,265,953	44,941,232	11,238,889	0	222,472	99,668,546
3/1/05	48,801,170	40,603,434	11,981,462	0	284,859	101,670,925
4/1/05	44,285,182	44,453,695	12,004,687	0	230,789	100,974,353
5/1/05	48,959,906	58,131,068	13,040,362	0	268,833	120,400,169
6/1/05	76,278,177	60,822,663	12,930,520	0	211,194	150,242,554
7/1/05	106,269,231	66,889,302	12,783,972	0	208,349	186,150,854
8/1/05	93,875,769	58,813,039	13,202,321	0	241,236	166,132,365
9/1/05	73,385,812	57,569,676	13,035,856	0	247,481	144,238,825
10/1/05	49,118,342	52,576,483	13,597,266	0	251,667	115,543,758
11/1/05	39,457,479	45,745,626	12,879,745	0	290,134	98,372,984
12/1/05	61,841,359	47,687,780	13,496,905	0	262,568	123,288,612
1/1/06	59,831,417	44,480,774	13,640,565	0	244,739	118,197,495
2/1/06	46,909,913	45,059,925	11,347,764	0	257,655	103,575,257
3/1/06	56,014,171	48,050,555	12,789,756	0	280,809	117,135,291
4/1/06	43,041,331	46,983,834	12,500,254	0	247,706	102,773,125
5/1/06	61,539,045	61,049,199	13,893,786	0	237,751	136,719,781
6/1/06	88,846,341	64,644,094	13,706,280	0	186,218	167,382,933
7/1/06	114,212,065	67,304,427	12,948,790	0	219,828	194,685,111
8/1/06	102,517,838	66,147,232	13,796,104	0	232,414	182,693,589
9/1/06	76,869,836	55,165,323	12,652,405	0	215,512	144,903,076
10/1/06	50,372,478	55,026,020	12,732,004	0	266,598	118,397,100
11/1/06	40,301,597	48,121,960	11,656,828	0	275,084	100,355,469
12/1/06	63,524,339	48,623,599	11,218,646	0	269,941	123,636,525
1/1/07	77,796,226	45,812,761	11,779,385	0	231,711	135,620,083
2/1/07	53,080,354	45,216,837	11,795,040	0	260,771	110,353,002
3/1/07	50,629,291	50,008,001	13,059,071	0	257,280	113,953,643
4/1/07	46,367,132	50,604,610	11,890,839	0	123,251	108,985,831
5/1/07	63,090,150	62,488,054	12,571,549	0	177,315	138,327,068
6/1/07	88,507,604	62,061,581	12,214,354	0	138,705	162,922,244
7/1/07	113,515,194	71,428,115	12,603,260	0	212,327	197,758,896
8/1/07	106,893,771	70,409,003	13,190,581	0	159,169	190,652,524
9/1/07	93,500,773	60,658,421	12,803,421	0	42,147	167,004,762
10/1/07	42,144,261	54,898,783	13,387,125	0	359,769	110,789,939
11/1/07	48,974,718	51,720,683	11,848,860	0	186,994	112,731,255
12/1/07	69,611,607	50,956,174	12,058,340	0	97,952	132,724,073
1/1/08	71,943,454	49,181,400	12,837,262	0	327,447	134,289,563

2/1/08	60,074,202	48,016,165	12,103,177	0	206,297	120,399,841
3/1/08	51,295,916	49,315,595	13,378,634	0	74,104	114,064,249
4/1/08	44,888,529	57,016,009	13,165,074	0	315,702	115,385,314
5/1/08	57,889,155	57,922,263	13,468,090	0	119,357	129,398,865
6/1/08	80,899,635	65,948,499	14,002,131	0	136,094	160,986,359
7/1/08	110,013,739	66,972,525	14,310,507	0	135,542	191,432,313
8/1/08	105,086,031	67,432,655	14,586,337	0	174,176	187,279,199
9/1/08	84,667,076	64,712,521	13,604,081	0	182,480	163,166,158
10/1/08	49,228,643	50,371,620	13,853,523	0	181,120	113,634,906
11/1/08	46,536,367	52,183,571	10,062,326	0	145,687	108,927,951
12/1/08	59,966,877	51,361,356	12,778,378	0	238,624	124,345,235
1/1/09	67,799,701	48,014,198	8,257,789	10,647,000	224,800	134,943,488
2/1/09	52,859,325	45,708,472	8,771,707	9,805,000	190,179	117,334,683
3/1/09	45,910,966	51,413,441	9,841,225	13,475,000	196,933	120,837,565
4/1/09	46,428,581	51,728,158	10,377,664	15,117,000	170,223	123,821,626
5/1/09	68,415,877	62,789,328	11,090,287	11,772,000	153,185	154,220,677
6/1/09	69,281,884	63,021,940	10,055,048	12,791,000	152,145	155,302,017
7/1/09	108,562,443	72,658,046	10,433,005	15,082,000	164,991	206,900,485
8/1/09	110,229,160	70,842,306	11,136,232	14,530,000	164,282	206,901,980
9/1/09	82,089,071	65,794,937	10,967,177	13,424,000	169,458	172,444,643
10/1/09	48,595,836	56,760,669	10,452,114	15,720,000	195,669	131,724,288
11/1/09	46,390,753	54,279,880	10,234,062	15,068,000	212,453	126,185,148
12/1/09	67,231,810	52,828,890	9,774,388	16,043,000	225,539	146,103,627
1/1/10	70,507,462	50,258,740	10,170,314	15,798,000	136,207	146,870,723
2/1/10	55,403,070	46,939,644	9,782,157	13,544,000	174,566	125,843,437
3/1/10	49,434,244	55,988,396	10,002,813	17,510,000	255,101	133,190,554
4/1/10	47,392,792	54,024,349	9,286,742	16,770,000	155,498	127,629,381
5/1/10	51,037,989	62,253,316	6,792,792	17,343,000	145,077	137,572,174
6/1/10	77,490,590	65,020,664	11,446,422	17,174,000	173,654	171,305,330
7/1/10	111,981,254	75,122,666	11,812,629	16,986,750	125,513	216,028,812
8/1/10	107,466,032	71,878,536	11,250,821	17,837,250	189,843	208,622,482
9/1/10	81,743,639	62,609,514	10,690,694	16,290,750	164,760	171,499,357
10/1/10	55,162,299	55,579,334	11,125,333	20,013,400	163,895	142,044,261
11/1/10	50,193,354	53,897,294	10,272,975	19,702,150	231,728	134,297,501
12/1/10	62,539,376	50,738,544	8,538,080	20,337,950	102,200	142,256,150
1/1/11	70,506,656	51,548,525	10,706,604	20,470,700	170,578	153,403,063
2/1/11	60,030,533	49,621,419	8,611,454	17,423,500	142,877	135,829,783
3/1/11	49,628,559	51,992,180	10,332,488	20,836,000	161,801	132,951,028
4/1/11	47,823,523	53,466,994	8,413,962	20,814,350	131,813	130,650,642
5/1/11	51,894,987	58,433,967	11,290,098	21,723,650	131,655	143,474,357
6/1/11	73,546,688	70,338,145	10,989,314	21,404,250	108,842	176,387,239
7/1/11	104,511,913	63,794,077	12,019,732	22,047,100	89,958	202,462,780
8/1/11	109,513,738	74,838,882	12,150,316	15,979,578	126,985	212,609,499
9/1/11	84,538,093	60,868,752	10,760,243	11,774,283	118,493	168,059,864
10/1/11	54,786,847	55,873,331	11,824,379	9,581,081	150,516	132,216,154
11/1/11	48,955,203	52,949,010	10,509,184	9,028,943	190,839	121,633,179
12/1/11	72,057,767	51,970,594	9,497,474	9,535,637	164,793	143,226,266
1/1/12	65,733,165	48,332,238	11,304,874	9,296,075	138,805	134,805,157
2/1/12	52,628,602	50,420,781	9,511,705	8,606,150	165,230	121,332,468
3/1/12	52,336,185	53,893,544	10,839,982	9,699,569	126,525	126,895,805
4/1/12	50,771,687	57,101,370	10,492,374	9,155,570	164,153	127,685,154
5/1/12	67,442,397	65,188,433	10,965,395	8,913,775	135,398	152,645,399
6/1/12	86,314,033	68,622,862	10,297,415	9,514,288	78,369	174,826,967
7/1/12	99,263,873	65,680,284	11,245,233	9,303,329	133,335	185,626,054
8/1/12	108,297,273	68,242,272	11,317,386	5,554,548	139,370	193,550,850
9/1/12	82,747,097	63,152,839	10,389,546	5,023,532	117,607	161,430,621
10/1/12	59,183,162	54,479,976	11,564,864	4,176,173	157,478	129,561,653

11/1/12	47,134,941	54,575,296	7,103,466	5,484,683	158,614	114,457,001
12/1/12	63,931,510	56,497,349	6,188,944	5,960,862	145,610	132,724,275
1/1/13	82,378,659	48,995,832	7,298,527	6,652,245	174,226	145,499,489
2/1/13	57,694,033	49,939,974	6,811,316	2,985,131	313,901	117,744,355
3/1/13	50,139,201	48,797,240	8,131,497	3,562,498	67,188	110,697,624
4/1/13	47,382,208	58,374,296	7,895,451	4,239,368	133,757	118,025,080
5/1/13	63,942,437	63,509,191	8,282,653	6,555,723	151,069	142,441,073
6/1/13	89,844,432	72,038,931	8,426,706	5,237,070	86,931	175,634,070
7/1/13	112,480,385	69,538,054	8,389,880	6,230,855	125,035	196,764,209
8/1/13	100,693,447	67,695,659	8,613,094	5,439,107	150,226	182,591,533
9/1/13	73,695,238	59,138,317	7,663,531	4,600,028	152,019	145,249,133
10/1/13	49,603,561	54,501,348	8,387,625	4,162,262	173,912	116,828,709
11/1/13	46,200,759	53,691,561	7,934,926	4,930,318	186,514	112,944,079
12/1/13	69,562,377	52,272,367	6,775,799	6,084,295	192,897	134,887,735
1/1/14	64,506,394	48,110,287	7,837,873	4,399,912	176,536	125,031,002
2/1/14	47,415,456	49,628,463	7,091,435	4,671,596	139,803	108,946,753
3/1/14	47,088,366	54,433,231	8,069,547	5,344,566	171,541	115,107,250
4/1/14	50,931,843	56,072,424	7,670,084	5,343,467	161,235	120,179,053
5/1/14	61,199,342	64,729,278	8,592,013	5,288,519	134,979	139,944,132
6/1/14	87,688,812	68,920,615	7,655,492	6,023,080	114,809	170,402,808
7/1/14	108,428,290	69,636,660	8,165,177	6,537,041	120,867	192,888,036
8/1/14	94,710,131	65,726,993	7,965,069	4,998,313	141,573	173,542,079
9/1/14	83,523,066	62,974,695	8,158,526	5,243,299	155,478	160,055,065
10/1/14	58,151,344	56,526,048	8,144,703	5,935,339	151,906	128,909,340
11/1/14	46,759,813	54,135,898	7,118,771	5,637,485	178,121	113,830,089
12/1/14	65,536,151	51,757,597	6,296,583	4,791,449	228,026	128,609,807
1/1/15	67,995,824	48,383,539	6,503,887	3,397,070	159,235	126,439,556
2/1/15	45,164,464	47,731,885	6,308,359	1,528,899	151,914	100,885,521
3/1/15	52,296,470	52,169,493	7,162,280	1,295,658	186,183	113,110,085
4/1/15	49,648,281	51,361,769	7,585,942	1,244,973	143,772	109,984,737
5/1/15	54,011,292	57,971,263	7,905,474	1,222,627	137,220	121,247,877
6/1/15	90,973,546	69,337,166	8,137,601	1,187,174	136,230	169,771,718
7/1/15	100,983,695	62,155,217	7,915,981	1,144,371	103,484	172,302,748
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7/1/17						

Date	Total Residential	Total Commercial	Total Industrial	Total Mining	Total Other	Total
9/1/03	67,081	8,925	4	0	72	76,082
10/1/03	67,433	8,947	4	0	252	76,637
11/1/03	67,185	8,939	4	0	249	76,377
12/1/03	67,592	9,032	6	0	605	77,235
1/1/04	68,054	9,061	4	0	249	77,368
2/1/04	68,235	9,064	8	0	250	77,557
3/1/04	68,688	9,192	4	0	247	78,131
4/1/04	69,063	9,228	4	0	248	78,543
5/1/04	69,041	9,128	4	0	247	78,420
6/1/04	69,624	9,143	4	0	250	79,021
7/1/04	69,909	9,199	4	0	250	79,362
8/1/04	70,129	9,242	4	0	250	79,625
9/1/04	70,339	9,279	4	0	250	79,872
10/1/04	70,588	9,305	4	0	252	80,149
11/1/04	71,026	9,376	4	0	250	80,656
12/1/04	71,181	9,583	4	0	251	81,019
1/1/05	71,438	9,468	4	0	253	81,163
2/1/05	70,965	9,434	4	0	250	80,653
3/1/05	72,250	9,502	4	0	250	82,006
4/1/05	72,486	9,498	4	0	251	82,239
5/1/05	72,667	9,566	4	0	251	82,487
6/1/05	73,144	9,567	4	0	251	82,965
7/1/05	73,251	9,546	4	0	251	83,051
8/1/05	73,861	9,577	4	0	249	83,692
9/1/05	73,931	9,637	4	0	253	83,825
10/1/05	74,137	9,649	4	0	251	84,041
11/1/05	74,433	9,673	4	0	251	84,360
12/1/05	74,589	9,694	4	0	250	84,537
1/1/06	74,978	9,711	6	0	249	84,944
2/1/06	75,499	9,747	7	0	248	85,501
3/1/06	75,835	9,774	7	0	248	85,864
4/1/06	76,147	9,826	7	0	248	86,228
5/1/06	76,426	9,862	7	0	248	86,543
6/1/06	76,633	9,883	7	0	248	86,771
7/1/06	76,897	9,908	7	0	248	87,060
8/1/06	77,159	9,938	7	0	248	87,352
9/1/06	77,384	10,011	7	0	248	87,650
10/1/06	77,786	10,028	13	0	248	88,075
11/1/06	77,786	10,028	13	0	248	88,075
12/1/06	78,204	10,080	12	0	248	88,544
1/1/07	78,444	10,085	13	0	251	88,793
2/1/07	78,725	10,098	13	0	251	89,087
3/1/07	78,872	10,112	7	0	251	89,242
4/1/07	78,858	10,108	7	0	251	89,224
5/1/07	79,096	10,122	7	0	252	89,477
6/1/07	79,142	10,140	7	0	252	89,541
7/1/07	79,059	10,152	7	0	252	89,470
8/1/07	79,054	10,167	7	0	252	89,480
9/1/07	79,274	10,214	7	0	252	89,747
10/1/07	79,236	10,252	7	0	253	89,748
11/1/07	79,336	10,265	7	0	253	89,861

12/1/07	79,433	10,297	7	0	254	89,991
1/1/08	79,471	10,298	8	0	257	90,034
2/1/08	79,507	10,309	8	0	255	90,079
3/1/08	79,454	10,342	8	0	255	90,059
4/1/08	79,492	10,336	8	0	255	90,091
5/1/08	79,449	10,335	8	0	256	90,048
6/1/08	79,437	10,349	8	0	257	90,051
7/1/08	79,463	10,363	8	0	257	90,091
8/1/08	79,534	10,370	8	0	257	90,169
9/1/08	79,267	10,338	8	0	258	89,871
10/1/08	79,084	10,356	8	0	258	89,706
11/1/08	79,228	10,369	9	0	258	89,864
12/1/08	79,149	10,358	9	0	259	89,775
1/1/09	79,177	10,347	7	1	260	89,792
2/1/09	79,557	10,364	7	1	260	90,189
3/1/09	79,490	10,355	7	1	262	90,115
4/1/09	79,509	10,363	7	1	262	90,142
5/1/09	79,614	10,365	7	1	264	90,251
6/1/09	79,366	10,338	7	1	264	89,976
7/1/09	79,477	10,326	7	1	264	90,075
8/1/09	79,505	10,317	7	1	265	90,095
9/1/09	79,445	10,328	7	1	266	90,047
10/1/09	79,474	10,339	7	1	266	90,087
11/1/09	79,544	10,343	7	1	266	90,161
12/1/09	79,641	10,352	7	1	266	90,267
1/1/10	79,837	10,352	7	1	266	90,463
2/1/10	80,101	10,361	7	1	266	90,736
3/1/10	80,131	10,347	7	1	266	90,752
4/1/10	80,168	10,361	7	1	266	90,803
5/1/10	80,217	10,361	7	1	266	90,852
6/1/10	80,242	10,387	8	2	266	90,905
7/1/10	80,286	10,386	7	2	266	90,947
8/1/10	80,171	10,356	6	2	266	90,801
9/1/10	80,189	10,357	5	2	266	90,819
10/1/10	80,222	10,363	5	2	261	90,853
11/1/10	80,192	10,355	5	2	258	90,812
12/1/10	80,257	10,363	5	2	254	90,881
1/1/11	80,425	10,372	5	2	249	91,053
2/1/11	80,542	10,390	5	2	249	91,188
3/1/11	80,673	10,393	5	2	249	91,322
4/1/11	80,586	10,395	5	2	249	91,237
5/1/11	80,552	10,399	5	2	249	91,207
6/1/11	80,527	10,409	5	2	249	91,192
7/1/11	80,598	10,414	5	2	249	91,268
8/1/11	80,622	10,406	5	2	249	91,284
9/1/11	80,601	10,406	5	2	248	91,262
10/1/11	80,506	10,411	5	2	248	91,172
11/1/11	80,612	10,427	5	2	363	91,409
12/1/11	80,671	10,429	5	2	363	91,470
1/1/12	80,702	10,432	4	2	360	91,500
2/1/12	80,761	10,427	5	2	473	91,668
3/1/12	80,904	10,440	5	2	474	91,825
4/1/12	80,815	10,453	5	2	475	91,750
5/1/12	80,754	10,471	5	2	475	91,707
6/1/12	80,815	10,469	5	2	475	91,766

7/1/12	80,798	10,492	5	2	473	91,770
8/1/12	80,894	10,485	5	2	473	91,859
9/1/12	80,887	10,495	5	2	473	91,862
10/1/12	80,939	10,505	4	2	477	91,927
11/1/12	80,996	10,517	4	2	528	92,047
12/1/12	81,111	10,513	4	2	531	92,161
1/1/13	81,277	10,521	4	2	531	92,335
2/1/13	81,336	10,536	4	2	531	92,409
3/1/13	81,406	10,584	4	2	533	92,529
4/1/13	81,273	10,577	4	2	533	92,389
5/1/13	81,330	10,579	4	2	533	92,448
6/1/13	81,412	10,573	4	2	533	92,524
7/1/13	81,382	10,585	4	2	534	92,507
8/1/13	81,387	10,572	4	2	573	92,538
9/1/13	81,359	10,594	4	2	576	92,535
10/1/13	81,412	10,621	4	2	582	92,621
11/1/13	81,542	10,666	4	2	580	92,794
12/1/13	81,677	10,676	4	2	583	92,942
1/1/14	81,800	10,665	4	2	583	93,054
2/1/14	81,940	10,683	4	2	583	93,212
3/1/14	81,928	10,686	4	2	584	93,204
4/1/14	81,935	10,694	4	2	584	93,219
5/1/14	81,993	10,694	4	2	585	93,278
6/1/14	82,098	10,712	4	2	585	93,401
7/1/14	82,108	10,722	4	2	585	93,421
8/1/14	82,210	10,722	4	2	585	93,523
9/1/14	82,179	10,744	4	2	585	93,514
10/1/14	82,258	10,749	4	2	586	93,599
11/1/14	82,396	10,751	4	2	587	93,740
12/1/14	82,438	10,737	4	2	588	93,769
1/1/15	82,522	10,741	4	1	588	93,856
2/1/15	82,654	10,747	4	1	588	93,994
3/1/15	82,645	10,759	4	1	588	93,997
4/1/15	82,625	10,782	4	1	588	94,000
5/1/15	82,676	10,784	4	1	588	94,053
6/1/15	82,698	10,785	4	1	589	94,077
7/1/15	82,894	10,798	4	1	589	94,286
8/1/15						
9/1/15						
10/1/15						
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11/1/16						
12/1/16						
1/1/17						

STF 12.3

What is UNSE's current estimate of the number of electric vehicles (EVs) in its service territory?

RESPONSE:

The Company has no information currently available that is responsive to this request.

RESPONDENT:

Todd Stocksdale/Craig Jones

WITNESS:

Craig Jones

UNS ELECTRIC INC.'S RESPONSE TO STAFF'S TWELFTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
SEPTEMBER 24, 2015

STF 12.6

Has UNSE performed studies to determine the ability of its existing transformers to absorb increased load due to EVs?

RESPONSE:

No.

RESPONDENT:

Todd Stocksdale/Craig Jones

WITNESS:

Craig Jones

UDR 2.10

For each month since July 1, 2012 through December 31, 2014, please provide:

i. Total number of residential bills;

ii. Number of bills with usage less than 300 kWh;

iii. Number of bills with usage between 300 and 1000 kWh; and

iv. Number of bills with usage over 1000 kWh.

RESPONSE:

Please see UDR 2.10 Bill Frequency.xlsx for monthly data from July 1, 2012 through December 31, 2014. The Excel file is not identified by Bates numbers.

RESPONDENT:

Anne Trostle (a) / Greg Strang (a-d)

WITNESS:

Dallas Dukes

UNS Electric Bill Frequency Data

Total Residential RES-01

MONTH	BILL_COUNT_0_TO_300	BILL_COUNT_301_TO_1000	BILL_COUNT_ABOVE_1000	TOTAL_BILL_COUNT
201207	11974	23223	38784	73981
201208	12329	24915	43416	80660
201209	10920	22045	34062	67027
201210	18053	36251	26441	80745
201211	19692	37852	12721	70265
201212	16989	34237	16313	67539
201301	14574	31997	30231	76802
201302	15292	34440	21234	70966
201303	17860	40134	16268	74262
201304	21936	43919	11420	77275
201305	20532	39631	17364	77527
201306	14001	26754	29962	70717
201307	11429	22079	44065	77573
201308	11843	24264	41329	77436
201309	12247	25579	33282	71108
201310	21209	40755	18478	80442
201311	20848	37947	9692	68487
201312	16615	34205	20567	71387
201401	15832	36656	25862	78350
201402	17267	39418	15003	71688
201403	20894	44315	10148	75357
201404	22310	45222	11433	78965
201405	20739	39305	15541	75585
201406	15306	29618	30815	75739
201407	12210	24551	42284	79045
201408	11888	24530	39446	75864
201409	12711	26312	36811	75834
201410	19032	38703	24443	82178
201411	18732	35485	11654	65871
201412	18208	38853	18621	75682

Residential RES-01 Net Metering

MONTH	BILL_COUNT_0_TO_300	BILL_COUNT_301_TO_1000	BILL_COUNT_ABOVE_1000	TOTAL_BILL_COUNT
201207	511	139	177	827
201208	451	190	285	926
201209	366	180	228	774
201210	602	254	117	973
201211	643	150	49	842
201212	522	178	77	777
201301	525	259	206	990
201302	493	216	101	810
201303	718	134	55	907
201304	878	99	30	1007
201305	835	108	34	977
201306	685	105	102	892
201307	610	139	244	993
201308	556	195	267	1018
201309	464	230	222	916
201310	828	169	62	1059
201311	746	125	35	906
201312	634	225	96	955
201401	686	262	126	1074
201402	743	193	63	999
201403	914	120	36	1070
201404	1005	108	34	1147
201405	977	92	39	1108
201406	878	147	110	1135
201407	803	182	235	1220
201408	665	222	297	1184
201409	633	318	251	1202
201410	863	322	125	1310
201411	854	180	55	1089
201412	926	427	256	1609

TASC 1.10

Re: page 4, lines 24-25: "policies such as net metering [] encourages customers to oversize their solar systems beyond their average load."

a. What is the average utility bill for solar customers before going solar?

b. What is the average utility bill for solar customers after going solar?

RESPONSE:

a.-b. Please see UNS Electric's supplemental response to UDR 1.001 dated July 30, 2015, specifically files RES Demand-DG_04-29-15_FINAL_v1.xlsx and SGS Demand-DG_04-29-15_FINAL_v1.xlsx.

RESPONDENT:

Rick Bachmeier

WITNESS:

Carmine Tilghman

TASC 1.13

Re: page 7, lines 14-17. "The Renewable Credit Rate - currently proposed to be 5.84 cents per kWh - is equivalent to the most recent utility scale renewable energy purchased power agreement connected to the distribution system of UNS Electric' s affiliate, TEP."

a. Please provide all documentation, assumptions, and workpapers used in determining the 5.84 cents per kWh Renewable Credit Rate.

b. Please describe in detail the methodology for determining future Renewable Credit Rates.

c. Please provide a forecast of future Renewable Credit Rates.

d. Were alterative methodologies considered? If so, please identify the alternatives and provide all documents describing the alterative(s) and why the proposed methodology was chosen over the alterative(s).

RESPONSE:

a. The 5.84 cents is simply the price paid by TEP for its most recent utility scale renewable energy purchase power agreement.

b. Future renewable credit rates would be determined by the most recent wholesale solar contract rate by either UNS Electric or its affiliate TEP, and would be filed with the Commission on an annual basis. This value may stay constant from one year to the next if no new contract has been executed; however, the Company would not allow the rate to remain unchanged for more than two years without supporting market data.

c. The Company cannot predict the future renewable credit rates.

d. The Company considered alternatives such as (i) the Company's avoided cost rate that is filed each year with the Commission or (ii) the Company's embedded fuel cost as approved in its most current rate case. It was determined that as long as the Company has a renewable energy requirement and would otherwise be procuring renewable energy, it was reasonable to pay the prevailing wholesale market price for renewable energy on our distribution grid.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

TASC 1.34

Re: page 21, lines 3-5.

a. How many of the residential solar PV systems in UNS's territory are sized to "yield zero excess kWh."

b. Please provide all workpapers supporting the table on page 21.

c. What rates are assumed in this table? I.e., Current, or the proposed 3-part?

d. If "current," please replicate the table with UNS's proposed 3-part rate.

RESPONSE:

a. The Company does not track this information..

b. Please see UNS Electric's supplemental response to UDR 1.001 dated July 30, 2015, specifically file RES Demand-DG_04-29-15_FINAL_v1.xlsx.

c. All comparisons in the table referenced in part "c" assumes the proposed 3-part rates.

d. The requested information is provided in the table on page 29 of Mr. Dukes' Direct Testimony and in the Excel file identified in the response to TASC 1.34(b).

RESPONDENT:

Carmine Tilghman (a) / Rick Bachmeier (b-d)

WITNESS:

Dallas Dukes / Carmine Tilghman

TASC 3.2

Tilghman p. 6, lines 14-23

Please provide all studies, conducted by or for UNS concerning:

a. Increased operations and maintenance costs, equipment wear and tear, resulting from distributed solar generation.

b. Energy flowing back up through the distribution system resulting from distributed solar generation.

c. For each item a through b, if UNS has not such studies, please provide any and all data, reports or studies UNS relied upon for each statement. For each source, please provide specific citations (e.g., page number).

RESPONSE:

a. The idea that intermittent resources create additional challenges and service on the distribution grid is well documented throughout the industry. Whitepapers, presentations, and other forms of documentation are widely available from organizations such as National Renewable Engineering Laboratory ("NREL"), Massachusetts Institute of Technology ("MIT"), Lawrence Berkley Engineering Laboratory ("LBEL"), Solar Electric Power Association ("SEPA"), Southwest Variable Energy Resource Initiative's ("SVERI"), and others. All of these documents are public and easily attainable by TASC. While there are far too many to list in this response, several are listed in part "c" below.

b. The Company has not completed any studies on back flow. However, the Company sees reverse flow at its Sacramento Substation, and its sister company, TEP, routinely has back flow on its circuits and has recently discovered reverse flow on individual phases on at least one of its circuits.

c. Listed below are examples of reports highlighting additional costs and O&M associated with variable generation.

   1. Western Electricity Coordinating Council's Variable Generation Subcommittee Marketing Workgroup whitepaper – "Electricity Markets and Variable Generation Integration". Read entire report pages 1-56.
   2. Western Electricity Coordinating Council's – "WECC Variable Generation Planning Reference Book: A Guidebook for Including Variable Generation in the Planning Process". Read report pages 1-161.
   3. MIT Study on the Future of Solar Energy, specifically Chapter 7 – Integration of Distributed Photovoltaic Generators. https://mitei.mit.edu/futureofsolar
   4. North American Electric Reliability Corporation (NERC) Special Report: Accommodating High Levels of Variable Generation, April 2009. http://www.nerc.com/files/IVGTF_Report_041609.pdf Read all pages.
   5. Western Wind and Solar Integration Study – "Analysis of Cycling Costs in Western Wind and Solar Integration Study". http://www.nrel.gov/docs/fy12osti/54864.pdf. Read entire report, pages 1 through 19.
   6. NREL – "Fundamental Drivers of the Cost and Price of Operating Reserves". http://www.nrel.gov/docs/fy13osti/58491.pdf Read entire report pages 1-57.
   7. Intertek APTECH report prepared for NREL and WECC – "Power Plant Cycling

Costs" – All pages with specific references to the report Preface and Executive Summary.

This list is sample of documents presented by various research and institutional entities that support and validate Mr. Tilghman's statements.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

WRA 1.06

Does solar DG production shift the time of day that peak load occurs on the UNSE system? Please provide data that supports your answer. If this data is not available, please explain why.

RESPONSE:

Solar production peaks at noon and its production significantly reduced by summer peak demand hours (between 4-5 pm). As such, its low ELCC value has not yet had the effect of moving or shifting the time of day that peak load occurs. The Company's annual system peak has occurred on the following dates and times over the last 5 years (since the significant introduction of distribute resources):

2015: August 16, HE 1700

2014: July 24, HE 1600

2013: Jun 28, HE 1700

2012: Aug 8, HE 1600

2011: June 27, HE 1600

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

UNS ELECTRIC INC.'S RESPONSE TO WESTERN RESOURCE ADVOCATES' FIRST SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
October 29, 2015

WRA 1.15

On average, do peak monthly loads for residential customers with DG on the UNSE system differ from peak monthly loads for residential customers without DG? Please provide any data, studies, reports, or documents the Company relies upon for its conclusion.

RESPONSE:

The Company has no actual data on whether monthly peak loads of residential customers with DG on the UNS Electric system differ from those of residential customers without DG. The Company does not possess metered monthly peak load data for all residential customers on the system, much less data on peak load differences between residential customers with and without DG.

RESPONDENT:

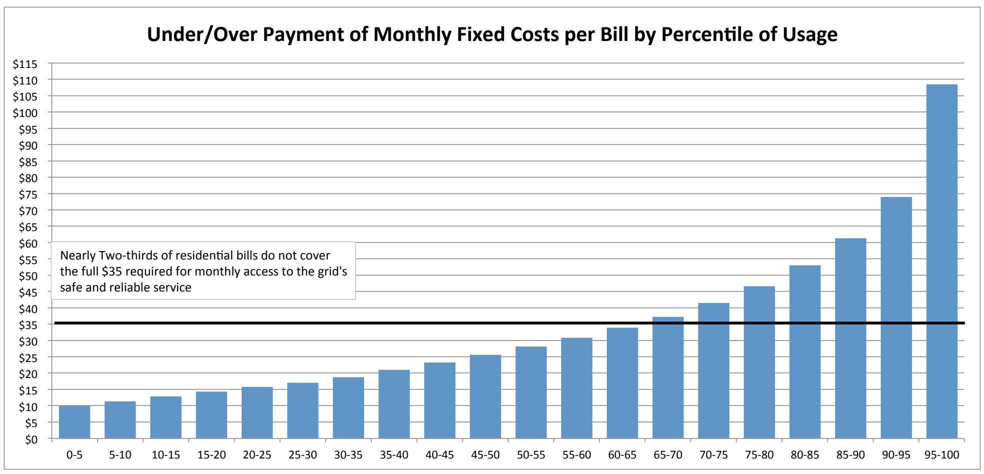
Rick Bachmeier / Carmine Tilghman

WITNESS:

Carmine Tilghman

	Year	c		Average_kWh	Average_TD	Sum_kWh	Sum_TD	Max_kWh	Max_TD	Min_kWh	Min_TD		
0	5	2010	43127	6.437452176	10.12424283	277628	436628.2204	30	10.579	0	10	0-5	0.0%
5	10	2010	43129	69.42303323	11.33986454	2994146	489077.0178	110	12.123	30	10.579	5-10	0.4%
10	15	2010	43128	148.903172	12.87383122	6421896	555222.5928	189	13.6477	110	12.123	10-15	0.9%
15	20	2010	43128	226.3757884	14.36905272	9763135	619708.5055	264	15.0952	189	13.6477	15-20	1.3%
20	25	2010	43129	300.1681699	15.79324568	12945953	681146.8929	335	16.4655	264	15.0952	20-25	1.8%
25	30	2010	43128	369.3401966	17.12851426	15928904	738718.5628	402	17.7887	335	16.4655	25-30	2.2%
30	35	2010	43128	436.2975329	18.96682026	18816640	818001.024	470	20.1245	402	17.7887	30-35	2.6%
35	40	2010	43128	503.3520219	21.27014195	21708566	917338.6821	538	22.4603	470	20.1245	35-40	3.0%
40	45	2010	43129	571.5094252	23.61134876	24648630	1018333.861	607	24.83045	538	22.4603	40-45	3.4%
45	50	2010	43128	642.7685031	26.05909808	27721320	1123876.782	680	27.338	607	24.83045	45-50	3.8%
50	55	2010	43128	718.7175849	28.66794904	30996852	1236391.306	760	30.086	680	27.338	50-55	4.2%
55	60	2010	43129	800.9988871	31.49431177	34546281	1358318.172	845	33.00575	760	30.086	55-60	4.7%
60	65	2010	43128	891.4297672	34.6006125	38445583	1492255.216	940	36.269	845	33.00575	60-65	5.2%
65	70	2010	43128	993.7218744	38.15886665	42857237	1645715.601	1050	40.25495	940	36.269	65-70	5.8%
70	75	2010	43129	1111.775928	42.63326145	47949784	1838729.933	1178	45.182822	1050	40.25495	70-75	6.5%
75	80	2010	43128	1250.850955	47.98751093	53946700	2069605.371	1330	51.03467	1178	45.182822	75-80	7.3%
80	85	2010	43128	1422.355198	54.59025279	61343335	2354368.422	1523	58.464977	1330	51.03467	80-85	8.4%
85	90	2010	43128	1648.71049	63.30470514	71105586	2730205.323	1791	68.782709	1523	58.464977	85-90	9.7%
90	95	2010	43129	1993.632707	76.58386557	85983385	3302985.538	2248	86.376752	1791	68.782709	90-95	11.7%
95	100	2010	43128	2922.00262	112.3251789	126020129	4844360.314	13520	520.33748	2248	86.376752	95-100	17.2%
0	5	2011	43209	6.362979935	10.12280551	274938	437396.3034	30	10.579	0	10	0-5	0.0%
5	10	2011	43210	70.60404999	11.36265816	3050801	490980.4593	110	12.123	30	10.579	5-10	0.4%
10	15	2011	43210	149.4233742	12.88387112	6456584	556712.0712	190	13.667	110	12.123	10-15	0.9%
15	20	2011	43210	227.2586207	14.38609138	9819845	621623.0085	265	15.1145	190	13.667	15-20	1.3%
20	25	2011	43210	301.0049063	15.80939469	13006422	683123.9446	336	16.4848	265	15.1145	20-25	1.8%
25	30	2011	43210	369.7740106	17.13731132	15977935	740503.2221	403	17.82305	336	16.4848	25-30	2.2%
30	35	2011	43210	436.956399	18.98945231	18880886	820534.2341	470	20.1245	403	17.82305	30-35	2.6%
35	40	2011	43210	503.1585744	21.26349703	21741482	918795.7067	537	22.42595	470	20.1245	35-40	3.0%
40	45	2011	43210	571.2083314	23.60100618	24681912	1019799.477	606	24.7961	537	22.42595	40-45	3.4%
45	50	2011	43210	641.934205	26.03043994	27737977	1124775.31	680	27.338	606	24.7961	45-50	3.8%
50	55	2011	43209	717.3937374	28.62247488	30997866	1236748.517	758	30.0173	680	27.338	50-55	4.2%
55	60	2011	43210	799.8078685	31.45340028	34559698	1359101.426	842	32.9027	758	30.0173	55-60	4.7%
60	65	2011	43210	890.1932192	34.55813708	38465249	1493257.103	940	36.269	842	32.9027	60-65	5.2%
65	70	2011	43210	992.349433	38.10856311	42879419	1646671.012	1049	40.216451	940	36.269	65-70	5.8%
70	75	2011	43210	1108.95906	42.52481487	47918121	1837497.25	1174	45.028826	1049	40.216451	70-75	6.5%
75	80	2011	43210	1247.170956	47.84583463	53890257	2067418.514	1325	50.842175	1174	45.028826	75-80	7.3%
80	85	2011	43210	1417.316848	54.39628133	61242261	2350463.316	1519	58.310981	1325	50.842175	80-85	8.3%
85	90	2011	43210	1643.793937	63.11542276	71028336	2727217.418	1789	68.705711	1519	58.310981	85-90	9.7%
90	95	2011	43210	1987.62025	76.352392	85885071	3299186.858	2240	86.06876	1789	68.705711	90-95	11.7%
95	100	2011	43210	2919.919371	112.2449758	126169716	4850105.406	13480	518.79752	2240	86.06876	95-100	17.2%
0	5	2012	44591	6.816151241	10.13155172	303939	451776.0227	30	10.579	0	10	0-5	0.0%
5	10	2012	44592	72.78321224	11.404716	3245549	508559.0957	113	12.1809	30	10.579	5-10	0.4%
10	15	2012	44592	153.3514083	12.95968218	6838246	577898.1478	193	13.7249	113	12.1809	10-15	0.9%
15	20	2012	44592	233.1898547	14.5005642	10398402	646609.1586	271	15.2303	193	13.7249	15-20	1.4%
20	25	2012	44592	308.1335217	15.94697697	13740290	711107.597	343	16.6199	271	15.2303	20-25	1.8%
25	30	2012	44592	378.1860423	17.31586449	16864072	772149.0294	412	18.1322	343	16.6199	25-30	2.2%
30	35	2012	44592	445.9745694	19.29922646	19886898	860591.1063	480	20.468	412	18.1322	30-35	2.6%
35	40	2012	44592	512.9122713	21.59853652	22871784	963121.9404	547	22.76945	480	20.468	35-40	3.0%
40	45	2012	44592	581.5569609	23.95648161	25932788	1068267.428	617	25.17395	547	22.76945	40-45	3.4%
45	50	2012	44592	653.3407113	26.42225343	29133769	1178221.125	690	27.6815	617	25.17395	45-50	3.8%
50	55	2012	44591	729.9775291	29.05472812	32550428	1295579.382	770	30.4295	690	27.6815	50-55	4.2%
55	60	2012	44592	813.1612845	31.91209012	36260488	1423023.923	858	33.4523	770	30.4295	55-60	4.7%
60	65	2012	44592	904.7478698	35.05808933	40344517.01	1563310.319	954	36.7499	858	33.4523	60-65	5.3%
65	70	2012	44592	1007.330396	38.65438165	44918877	1723676.187	1063	40.755437	954	36.7499	65-70	5.9%
70	75	2012	44592	1124.759508	43.13311632	50155276	1923391.923	1190	45.64481	1063	40.755437	70-75	6.5%
75	80	2012	44592	1262.86529	48.45005079	56313689	2160484.665	1340	51.41966	1190	45.64481	75-80	7.3%
80	85	2012	44592	1432.609011	54.9850143	63882901	2451891.758	1532	58.811468	1340	51.41966	80-85	8.3%
85	90	2012	44592	1657.554853	63.64520428	73913686	2838066.949	1800	69.1292	1532	58.811468	85-90	9.6%
90	95	2012	44592	1996.63776	76.69955713	89034071	3420186.651	2242	86.145758	1800	69.1292	90-95	11.6%
95	100	2012	44592	2911.142671	111.9070817	129813674	4990160.587	14320	551.13668	2242	86.145758	95-100	16.9%
0	5	2013	44828	6.712255733	10.12954654	300897	454087.3121	30	10.579	0	10	0-5	0.0%
5	10	2013	44829	72.20736577	11.39360216	3236984	510763.7912	111	12.1423	30	10.579	5-10	0.4%
10	15	2013	44830	151.6322329	12.92650209	6797673	579495.0889	191	13.6863	111	12.1423	10-15	0.9%
15	20	2013	44829	230.533204	14.44929084	10334573	647747.2589	269	15.1917	191	13.6863	15-20	1.3%
20	25	2013	44829	304.644672	15.87964217	13656916	711868.4788	340	16.562	269	15.1917	20-25	1.8%
25	30	2013	44829	374.2492137	17.23054506	16777218	772428.1046	409	18.02915	340	16.562	25-30	2.2%
30	35	2013	44829	441.535167	19.14673299	19793580	858328.893	475	20.29625	409	18.02915	30-35	2.6%
35	40	2013	44830	508.3235336	21.44091338	22788144.01	961196.1467	542	22.5977	475	20.29625	35-40	2.9%
40	45	2013	44829	577.4027973	23.81378609	25884390	1067548.217	613	25.03655	542	22.5977	40-45	3.3%
45	50	2013	44829	650.1250753	26.31179634	29144457	1179531.518	689	27.64715	613	25.03655	45-50	3.8%
50	55	2013	44829	727.9499877	28.98508208	32633270	1299372.244	770	30.4295	689	27.64715	50-55	4.2%
55	60	2013	44829	812.5389145	31.89071171	36425307	1429628.715	858	33.4523	770	30.4295	55-60	4.7%
60	65	2013	44830	905.515503	35.08445753	40594260	1572836.231	956	36.8186	858	33.4523	60-65	5.2%
65	70	2013	44829	1010.151331	38.75933202	45284074	1737542.095	1068	40.947932	956	36.8186	65-70	5.9%
70	75	2013	44829	1130.314997	43.34699707	50670891	1943202.532	1197	45.914303	1068	40.947932	70-75	6.6%
75	80	2013	44829	1271.436012	48.78001504	56997205	2186759.294	1350	51.80465	1197	45.914303	75-80	7.4%
80	85	2013	44829	1443.781035	55.41512605	64723260	2484204.686	1545	59.311955	1350	51.80465	80-85	8.4%
85	90	2013	44830	1671.598104	64.1858554	74937743	2877451.898	1815	69.706685	1545	59.311955	85-90	9.7%
90	95	2013	44829	2016.089273	77.4484209	90379266	3471935.261	2269	87.185231	1815	69.706685	90-95	11.7%
95	100	2013	44829	2946.51924	113.2690442	132089511	5077737.983	14720	566.53628	2269	87.185231	95-100	17.1%
0	5	2014	45657	6.583995444	10.12707111	300605.48	462371.6858	30	10.579	0	10	0-5	0.0%
5	10	2014	45657	71.86401319	11.38697545	3281095.25	519895.1383	111	12.1423	30	10.579	5-10	0.4%
10	15	2014	45658	150.8643388	12.91168174	6888163.98	589521.5648	190	13.667	111	12.1423	10-15	0.9%
15	20	2014	45657	228.0274442	14.40092967	10411049.02	657503.2461	265	15.1145	190	13.667	15-20	1.4%
20	25	2014	45658	299.4907609	15.78017168	13674149.16	720491.0788	333	16.4269	265	15.1145	20-25	1.8%
25	30	2014	45658	366.3302429	17.07017369	16725906.23	779389.9902	399	17.7007	333	16.4269	25-30	2.2%
30	35	2014	45657	430.8512285	18.7797809	19671374.54	857428.4567	463	19.88405	399	17.7007	30-35	2.6%
35	40	2014	45658	495.1811345	20.98947197	22608980.24	958337.3112	528	22.1168	463	19.88405	35-40	3.0%
40	45	2014	45657	561.0945229	23.25359686	25617892.63	1061689.472	595	24.41825	528	22.1168	40-45	3.4%
45	50	2014	45658	630.0086366	25.62079667	28764934.33	1169794.334	666	26.8571	595	24.41825	45-50	3.8%
50	55	2014	45658	703.148049	28.13313548	32104333.62	1284502.7	741	29.43335	666	26.8571	50-55	4.2%
55	60	2014	45657	782.5855921	30.86181509	35730510.38	1409057.892	825	32.31875	741	29.43335	55-60	4.7%
60	65	2014	45658	870.7142247	33.88903362	39755070.07	1547305.497	919	35.54765	825	32.31875	60-65	5.2%
65	70	2014	45657	969.7071814	37.29964206	44273920.78	1702989.758	1023	39.215477	919	35.54765	65-70	5.8%
70	75	2014	45658	1083.033594	41.52671035	49449147.85	1896026.541	1146	43.950854	1023	39.215477	70-75	6.5%
75	80	2014	45658	1216.880456	46.67968066	55560327.84	2131300.86	1292	49.571708	1146	43.950854	75-80	7.3%
80	85	2014	45657	1381.432614	53.01477419	63072068.84	2420495.545	1479	56.771021	1292	49.571708	80-85	8.3%
85	90	2014	45658	1598.116397	61.35688318	72966798.47	2801432.572	1736	66.665264	1479	56.771021	85-90	9.6%
90	95	2014	45657	1925.820059	73.97314645	87927166.43	3377391.947	2164	83.142836	1736	66.665264	90-95	11.6%
95	100	2014	45658	2822.086885	108.478523	128850843	4952912.402	12507	481.337993	2164	83.142836	95-100	17.0%

			2010	2011	2012	2013	2014	5 Year Average	
1.4%	10.12	0-5	$10	$10	$10	$10	$10	$10	35.048043
1.6%	11.34	5-10	$11	$11	$11	$11	$11	$11	35.048043
1.8%	12.87	10-15	$13	$13	$13	$13	$13	$13	
2.0%	14.37	15-20	$14	$14	$15	$14	$14	$14	
2.3%	15.79	20-25	$16	$16	$16	$16	$16	$16	
2.4%	17.13	25-30	$17	$17	$17	$17	$17	$17	
2.7%	18.97	30-35	$19	$19	$19	$19	$19	$19	
3.0%	21.27	35-40	$21	$21	$22	$21	$21	$21	
3.4%	23.61	40-45	$24	$24	$24	$24	$23	$24	
3.7%	26.06	45-50	$26	$26	$26	$26	$26	$26	
4.1%	28.67	50-55	$29	$29	$29	$29	$28	$29	
4.5%	31.49	55-60	$31	$31	$32	$32	$31	$32	
4.9%	34.60	60-65	$35	$35	$35	$35	$34	$35	
5.4%	38.16	65-70	$38	$38	$39	$39	$37	$38	
6.1%	42.63	70-75	$43	$43	$43	$43	$42	$43	
6.8%	47.99	75-80	$48	$48	$48	$49	$47	$48	
7.8%	54.59	80-85	$55	$54	$55	$55	$53	$54	
9.0%	63.30	85-90	$63	$63	$64	$64	$61	$63	
10.9%	76.58	90-95	$77	$76	$77	$77	$74	$76	
16.0%	112.33	95-100	$112	$112	$112	$113	$108	$112	
1.4%	10.12								
1.6%	11.36								
1.8%	12.88								
2.1%	14.39								
2.3%	15.81								
2.4%	17.14								
2.7%	18.99								
3.0%	21.26								
3.4%	23.60								
3.7%	26.03								
4.1%	28.62								
4.5%	31.45								
4.9%	34.56								
5.4%	38.11								
6.1%	42.52								
6.8%	47.85								
7.8%	54.40								
9.0%	63.12								
10.9%	76.35								
16.0%	112.24								
1.4%	10.13								
1.6%	11.40								
1.8%	12.96								
2.1%	14.50								
2.3%	15.95								
2.4%	17.32								
2.7%	19.30								
3.1%	21.60								
3.4%	23.96								
3.7%	26.42								
4.1%	29.05								
4.5%	31.91								
5.0%	35.06								
5.5%	38.65								
6.1%	43.13								
6.9%	48.45								
7.8%	54.99								
9.0%	63.65								
10.8%	76.70								
15.8%	111.91								
1.4%	10.13								
1.6%	11.39								
1.8%	12.93								
2.0%	14.45								
2.2%	15.88								
2.4%	17.23								
2.7%	19.15								
3.0%	21.44								
3.4%	23.81								
3.7%	26.31								
4.1%	28.99								
4.5%	31.89								
4.9%	35.08								
5.5%	38.76								
6.1%	43.35								
6.9%	48.78								
7.8%	55.42								
9.0%	64.19								
10.9%	77.45								
16.0%	113.27								
1.5%	10.13								
1.7%	11.39								
1.9%	12.91								
2.1%	14.40								
2.3%	15.78								
2.5%	17.07								
2.7%	18.78								
3.1%	20.99								
3.4%	23.25								
3.7%	25.62								
4.1%	28.13								
4.5%	30.86								
4.9%	33.89								
5.4%	37.30								
6.1%	41.53								
6.8%	46.68								
7.7%	53.01								
9.0%	61.36								
10.8%	73.97								
15.8%	108.48								



Load/PV System Summary:

Small Customer Monthly kWh	500	
Annual Customer Energy (kWh)	6,000	
Annual PV Production-South (kWh)	6,000	Note: Input for annual production in "Rate_PV Input" tab.
Annual PV Production-West (kWh)	5,074	
System Size	3.33	kW-DC
Initial System Cost	$ 5,833.22	

		Annual	January	February	March	April	May	June	July	August	September	October	November
	Day Count	365	31	28	31	30	31	30	31	31	30	31	30
			1	2	3	4	5	6	7	8	9	10	11
1	**Description**	**Annual**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**
2	Energy Use (kWh)	6,001	451	368	362	372	460	667	794	679	590	393	384
3	Total Peak Demand (kW)	4.16	3.40	3.26	3.14	3.27	3.65	3.86	4.16	3.91	3.80	3.26	3.15
4	Ratchet Minimum-Total (kW)	-	-	-	-	-	-	-	-	-	-	-	-
5	Net Demand at Peak (kW)	4.00	3.40	3.26	3.14	3.27	3.47	3.71	4.00	3.84	3.80	3.26	3.15
6	Ratchet Minimum-Net (kW)	-	-	-	-	-	-	-	-	-	-	-	-
7	Load Factor (Total Peak)	16.5%	17.8%	16.8%	15.5%	15.8%	16.9%	24.0%	25.7%	23.3%	21.6%	16.2%	16.9%
8													
9	Net Hourly Energy Delivered (kWh)	3,447	309	242	229	205	231	333	418	357	318	229	254
10	Net Hourly Energy Received (kBh)	3,448	225	259	355	418	419	274	222	256	259	307	253
11													
12	Total PV Output (kWh)	6,000	374	401	519	585	623	593	595	564	520	475	397
13	PV Output (max kW)	2.9	2.4	2.9	2.8	2.8	2.9	2.8	2.8	2.7	2.8	2.7	2.4
14	Capacity Factor	23.5%	21.3%	20.7%	24.7%	29.3%	28.7%	29.7%	28.8%	28.2%	25.9%	23.8%	22.9%
15													
16	Net-Metering Rollover		-	-	33	190	403	565	491	292	177	107	189
17	Billing kWh		77	-	-	-	-	-	-	-	-	-	-
18													
19													

			Loads without DG:					**PV kWh/kBh Data:**					
		1	2	3	4	5	6	7	8	9	10	11	12
			2014 Solar Billing Dets - 50th percentile			Scaled to:	6,000	**SAM PV scaled w/Annual Use**	**Solar House total PV out**	**Solar House Net kWh in**	**Solar House kBh**	**SAM PV scaled w/Bill Dets.**	**Scaled Net kWh in**
			kWh	kW	Load Factor	**kWh**	**kW**						
31	January	1	595	4.49	17.8%	**451**	**3.40**	445	324	245	200	374	309
28	February	2	485	4.30	16.8%	**368**	**3.26**	409	348	192	231	401	242
31	March	3	478	4.14	15.5%	**362**	**3.14**	543	450	181	316	519	229
30	April	4	491	4.31	15.8%	**372**	**3.27**	580	507	162	372	585	205
31	May	5	607	4.82	16.9%	**460**	**3.65**	577	540	183	373	623	231
30	June	6	880	5.10	24.0%	**667**	**3.86**	533	514	264	244	593	333
31	July	7	1,048	5.49	25.7%	**794**	**4.16**	515	516	331	198	595	418
31	August	8	896	5.16	23.3%	**679**	**3.91**	528	489	283	228	564	357
30	September	9	778	5.01	21.6%	**590**	**3.80**	496	451	252	231	520	318
31	October	10	518	4.30	16.2%	**393**	**3.26**	492	412	181	273	475	229
30	November	11	507	4.16	16.9%	**384**	**3.15**	455	344	201	225	397	254
31	December	12	635	4.64	18.4%	**481**	**3.52**	429	309	255	179	356	322
365			7,918	5.49	16.5%	**6,000**	**4.16**	6,000	5,204	2,730	3,070	6,000	3,447
30.4		Monthly Avg.	660	4.66	19.4%		**3.53**			88.9%	2,900		100.0%
				Annual kWh as % of South orientation		84.6%				50th pctl			

31
12
December
481
3.52
-
3.52
-
18.4%
322
201
356
2.3
20.5%
201
-

	Peak kW Scaling and Adjustments:						**Peak Shifting Analysis:**						**For Scaling 8760:**		**Check:**	
13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
Scaled kBh	Scaled net kW	Max net kW Hour Position	Max net kW Hour	Count	PV output at Peak	**net kW adj for DG**	Max kW Hour Position	Max kW Hour	Count	DG output at Peak	Max kW less PV	2014 Res Avg Hrly Profile Raw kWh	Raw kW	Scaled kWh	Scaled kW
225	3.40	116	1/5 19:00	1	-	**3.40**	116	1/5 19:00	1	-	3.40	410	0.88	451	3.40
259	3.26	813	2/3 20:00	1	-	**3.26**	813	2/3 20:00	1	-	3.26	337	0.85	368	3.26
355	3.14	1988	3/24 19:00	1	-	**3.14**	1988	3/24 19:00	1	-	3.14	337	0.72	362	3.14
418	3.27	2661	4/21 20:00	1	-	**3.27**	2661	4/21 20:00	1	-	3.27	332	0.84	372	3.27
419	3.47	3523	5/27 18:00	1	0.1813	**3.47**	3523	5/27 18:00	1	***0.1679***	***3.48***	436	1.49	460	3.65
274	3.56	4339	6/30 18:00	1	0.1510	**3.71**	4338	***6/30 17:00***	1	***0.6304***	***3.23***	707	2.20	667	3.86
222	3.44	4363	7/1 18:00	1	0.1556	**4.00**	4913	***7/24 16:00***	1	***1.2842***	***2.88***	880	2.51	794	4.16
256	3.42	5491	8/17 18:00	1	0.0731	**3.84**	5490	***8/17 17:00***	1	***0.5600***	***3.35***	754	2.22	679	3.91
259	3.41	5851	9/1 18:00	1	-	**3.80**	5849	***9/1 16:00***	2	***1.2288***	***2.57***	659	2.07	590	3.80
307	3.11	6666	10/5 17:00	1	-	**3.26**	6665	***10/5 16:00***	1	***1.1715***	***2.09***	399	1.08	393	3.26
253	3.15	7868	11/24 19:00	1	-	**3.15**	7868	11/24 19:00	1	-	3.15	352	0.80	384	3.15
201	3.52	8755	12/31 18:00	1	-	**3.52**	8755	12/31 18:00	1	-	3.52	451	1.27	481	3.52
3,447	3.56					**4.00**				1.28		6,055	2.51	6,000	4.16
3,447	**3.35**														
57.4%															

Load/PV System Summary:

Medium Customer Monthly kWh	900	
Annual Customer Energy (kWh)	10,800	
Annual PV Production-South (kWh)	10,800	Note: Input for annual production in "Rate_PV Input" tab.
Annual PV Production-West (kWh)	9,133	
System Size	6.00	kW-DC
Initial System Cost	$ 10,499.79	

		Day Count	365	31	28	31	30	31	30	31	31	30	31	30	31
				1	2	3	4	5	6	7	8	9	10	11	12
1	**Description**		**Annual**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
2	Energy Use (kWh)		10,800	805	627	640	640	845	1,236	1,428	1,251	1,102	738	639	849
3	Total Peak Demand (kW)		6.30	5.49	5.15	4.80	5.08	5.66	5.97	6.30	6.01	5.75	5.07	5.01	5.60
4	Ratchet Minimum-Total (kW)		-	-	-	-	-	-	-	-	-	-	-	-	-
5	Net Demand at Peak (kW)		6.02	5.49	5.15	4.80	5.08	5.33	5.70	6.02	5.88	5.75	5.07	5.01	5.60
6	Ratchet Minimum-Net (kW)		-	-	-	-	-	-	-	-	-	-	-	-	-
7	Load Factor (Total Peak)		19.6%	19.7%	18.1%	17.9%	17.5%	20.1%	28.8%	30.4%	28.0%	26.6%	19.5%	17.7%	20.4%
8															
9	Net Hourly Energy Delivered (kWh)		5,918	519	388	353	336	419	610	724	639	563	395	421	551
10	Net Hourly Energy Received (kBh)		5,918	413	459	620	704	677	455	382	426	427	525	455	375
11															
12	PV Output (kWh)		10,800	672	722	935	1,052	1,121	1,067	1,071	1,015	936	854	713	641
13	PV Output (max kW)		5.2	4.2	5.2	5.1	5.0	5.2	5.0	5.0	4.8	5.0	4.8	4.3	4.2
14	Capacity Factor		23.5%	21.3%	20.7%	24.7%	29.3%	28.7%	29.7%	28.8%	28.2%	25.9%	23.8%	22.9%	20.5%
15															
16	Net-Metering Rollover			-	-	95	390	802	1,078	910	553	316	151	267	341
17	Billing kWh			133	-	-	-	-	-	-	-	-	-	-	-
18															
19															

			Loads without DG:					**PV kWh/kBh Data**						
		1	2	3	4	5	6	7	8	9	10	11	12	13
			2014 Solar Billing Dets - 75th percentile			Scaled to:	10,800	**SAM PV scaled**	**Solar House**	**Solar House**	**Solar House**	**SAM PV scaled**	**Scaled**	**Scaled**
			kWh	kW	Load Factor	**kWh**	**kW**	**w/Annual Use**	**total PV out**	**Net kWh in**	**kBh**	**w/Bill Dets.**	**Net kWh in**	**kBh**
31	January	1	969	6.60	19.7%	**805**	**5.49**	800	539	427	348	672	519	413
28	February	2	754	6.20	18.1%	**627**	**5.15**	736	579	319	387	722	388	459
31	March	3	770	5.78	17.9%	**640**	**4.80**	978	750	290	522	935	353	620
30	April	4	770	6.12	17.5%	**640**	**5.08**	1,043	844	276	593	1,052	336	704
31	May	5	1,017	6.81	20.1%	**845**	**5.66**	1,038	899	344	570	1,121	419	677
30	June	6	1,487	7.18	28.8%	**1,236**	**5.97**	959	856	501	383	1,067	610	455
31	July	7	1,718	7.59	30.4%	**1,428**	**6.30**	927	859	595	322	1,071	724	382
31	August	8	1,505	7.23	28.0%	**1,251**	**6.01**	950	814	525	359	1,015	639	426
30	September	9	1,326	6.92	26.6%	**1,102**	**5.75**	894	751	463	360	936	563	427
31	October	10	888	6.11	19.6%	**738**	**5.07**	885	685	325	442	854	395	525
30	November	11	769	6.03	17.7%	**639**	**5.01**	818	572	346	383	713	421	455
31	December	12	1,021	6.74	20.4%	**849**	**5.60**	772	514	453	316	641	551	375
365			12,994	7.59	19.6%	**10,800**	**6.30**	10,800	8,662	4,864	4,985	10,800	5,918	5,918
30.4		Monthly Avg.	1,083	6.61	22.4%		**5.49**			97.6%	4,925		100.0%	5,918

Peak kW Scaling and Adjustments:						Peak Shifting Analysis:					For Scaling 8760:		Check:	
14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
											2014 Res Avg Hrly Profile			
Scaled net kW	Max net kW Hour Position	Max net kW Hour	Count	PV output at Peak	**net kW adj for DG**	Max kW Hour Position	Max kW Hour	Count	DG output at Peak	Max kW less PV	Raw kWh	Raw kW	Scaled kWh	Scaled kW
5.49	128	1/6 7:00	1	-	**5.49**	128	1/6 7:00	1	-	5.49	887	1.92	805	5.49
5.15	824	2/4 7:00	1	-	**5.15**	824	2/4 7:00	1	-	5.15	701	1.94	627	5.15
4.80	1988	3/24 19:00	1	-	**4.80**	1988	3/24 19:00	1	-	4.80	690	1.37	640	4.80
4.84	2659	4/21 18:00	1	-	**5.08**	2658	***4/21 17:00***	1	***0.8304***	***4.25***	722	2.07	640	5.08
5.00	3523	5/27 18:00	1	0.3263	**5.33**	3522	***5/27 17:00***	1	***1.1015***	***4.56***	989	3.25	845	5.66
5.55	4339	6/30 18:00	1	0.2719	**5.70**	4338	***6/30 17:00***	1	***1.1348***	***4.83***	1,481	4.09	1,236	5.97
5.35	4363	7/1 18:00	1	0.2801	**6.02**	4913	***7/24 16:00***	1	***2.3115***	***3.99***	1,793	4.52	1,428	6.30
5.30	5491	8/17 18:00	1	0.1315	**5.88**	5488	***8/17 15:00***	1	***3.0425***	***2.97***	1,548	4.09	1,251	6.01
5.16	5851	9/1 18:00	1	-	**5.75**	5848	***9/1 15:00***	2	***3.0935***	***2.65***	1,365	3.82	1,102	5.75
4.77	6666	10/5 17:00	1	-	**5.07**	6665	***10/5 16:00***	1	***2.1087***	***2.97***	876	2.51	738	5.07
5.01	7869	11/24 20:00	1	-	**5.01**	7869	11/24 20:00	1	-	5.01	747	1.65	639	5.01
5.60	8755	12/31 18:00	1	-	**5.60**	8755	12/31 18:00	1	-	5.60	1,010	2.73	849	5.60
5.60					**6.02**				3.09		12,809	4.52	10,800	6.30
5.17														

Load/PV System Summary:

Large Customer Monthly kWh	1,200	
Annual Customer Energy (kWh)	14,400	
Annual PV Production-South (kWh)	14,400	Note: Input for annual production in "Rate_PV Input" tab.
Annual PV Production-West (kWh)	12,178	
System Size	8.00	kW-DC
Initial System Cost	$ 13,999.72	

	Day Count	365	31	28	31	30	31	30	31	31	30	31	30	31
			1	2	3	4	5	6	7	8	9	10	11	12
1	**Description**	**Annual**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
2	Energy Use (kWh)	14,401	1,050	846	831	880	1,143	1,572	1,899	1,650	1,467	991	893	1,179
3	Total Peak Demand (kW)	7.55	6.69	6.29	5.78	6.22	6.73	7.14	7.55	6.95	6.84	5.96	5.87	6.87
4	Ratchet Minimum-Total (kW)	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Net Demand at Peak (kW)	7.13	6.69	6.29	5.78	6.22	6.29	6.77	7.13	6.78	6.84	5.96	5.80	6.87
6	Ratchet Minimum-Net (kW)	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Load Factor (Total Peak)	21.8%	21.1%	20.0%	19.3%	19.7%	22.8%	30.6%	33.8%	31.9%	29.8%	22.3%	21.1%	23.1%
8														
9	Net Hourly Energy Delivered (kWh)	7,702	700	505	464	422	534	781	948	822	745	523	509	749
10	Net Hourly Energy Received (kBh)	7,702	549	622	847	927	850	588	511	537	522	657	602	490
11														
12	PV Output (kWh)	14,400	897	963	1,246	1,403	1,495	1,423	1,428	1,353	1,248	1,139	951	855
13	PV Output (max kW)	7.0	5.7	6.9	6.8	6.6	7.0	6.7	6.7	6.4	6.7	6.4	5.8	5.6
14	Capacity Factor	23.5%	21.3%	20.7%	24.7%	29.3%	28.7%	29.7%	28.8%	28.2%	25.9%	23.8%	22.9%	20.5%
15														
16	Net-Metering Rollover		-	-	117	532	1,055	1,406	1,258	786	490	271	419	476
17	Billing kWh		153	-	-	-	-	-	-	-	-	-	-	-
18														
19														

		Loads without DG:					**PV kWh/kBh Data**						
	1	2	3	4	5	6	7	8	9	10	11	12	13
		2014 Solar Billing Dets - 90th percentile			Scaled to:	14,400	**SAM PV scaled**	**Solar House**	**Solar House**	**Solar House**	**SAM PV scaled**	**Scaled**	**Scaled**
		kWh	kW	Load Factor	**kWh**	**kW**	**w/Annual Use**	**total PV out**	**Net kWh in**	**kBh**	**w/Bill Dets.**	**Net kWh in**	**kBh**
31 January	1	1,361	8.67	21.1%	**1,050**	**6.69**	1,067	792	690	525	897	700	549
28 February	2	1,097	8.15	20.0%	**846**	**6.29**	982	850	498	595	963	505	622
31 March	3	1,077	7.49	19.3%	**831**	**5.78**	1,304	1,100	458	810	1,246	464	847
30 April	4	1,140	8.06	19.6%	**880**	**6.22**	1,391	1,238	416	886	1,403	422	927
31 May	5	1,481	8.72	22.8%	**1,143**	**6.73**	1,384	1,320	527	813	1,495	534	850
30 June	6	2,037	9.25	30.6%	**1,572**	**7.14**	1,279	1,257	770	562	1,423	781	588
31 July	7	2,461	9.78	33.8%	**1,899**	**7.55**	1,235	1,260	934	489	1,428	948	511
31 August	8	2,138	9.01	31.9%	**1,650**	**6.95**	1,267	1,195	811	513	1,353	822	537
30 September	9	1,902	8.87	29.8%	**1,467**	**6.84**	1,192	1,102	735	499	1,248	745	522
31 October	10	1,284	7.73	22.3%	**991**	**5.96**	1,180	1,006	516	629	1,139	523	657
30 November	11	1,158	7.61	21.1%	**893**	**5.87**	1,091	839	502	576	951	509	602
31 December	12	1,528	8.91	23.1%	**1,179**	**6.87**	1,029	755	739	468	855	749	490
365		18,664	9.78	21.8%	**14,400**	**7.55**	14,400	12,714	7,596	7,365	14,400	7,703	7,703
30.4	Monthly Avg.	1,555	8.52	25.0%		**6.57**			103.1%	7,480		100.0%	7,703

Peak kW Scaling and Adjustments:						**Peak Shifting Analysis:**					**For Scaling 8760:**		**Check:**	
14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
Scaled net kW	Max net kW Hour Position	Max net kW Hour	Count	PV output at Peak	**net kW adj for DG**	Max kW Hour Position	Max kW Hour	Count	DG output at Peak	Max kW less PV	2014 Res Avg Hrly Profile Raw kWh	Raw kW	Scaled kWh	Scaled kW
6.69	224	1/10 7:00	1	-	**6.69**	224	1/10 7:00	1	-	6.69	1,661	3.48	1,050	6.69
6.29	824	2/4 7:00	1	-	**6.29**	824	2/4 7:00	1	-	6.29	1,337	3.53	846	6.29
5.78	1460	3/2 19:00	1	-	**5.78**	1460	3/2 19:00	1	-	5.78	1,332	2.52	831	5.78
6.04	2659	4/21 18:00	1	-	**6.22**	2658	***4/21 17:00***	1	***1.1072***	***5.11***	1,374	3.56	880	6.22
5.83	3523	5/27 18:00	1	0.4352	**6.29**	3496	***5/26 15:00***	1	***4.1520***	***2.58***	1,738	4.96	1,143	6.73
6.67	4339	6/30 18:00	1	0.3626	**6.77**	4314	***6/29 17:00***	1	***1.5920***	***5.54***	2,344	5.64	1,572	7.14
6.42	4891	7/23 18:00	1	0.4186	**7.13**	4912	***7/24 15:00***	1	***4.1063***	***3.44***	2,772	6.19	1,899	7.55
6.34	5491	8/17 18:00	1	0.1754	**6.78**	5488	***8/17 15:00***	1	***4.0567***	***2.89***	2,428	5.84	1,650	6.95
6.37	5851	9/1 18:00	1	-	**6.84**	5850	***9/1 17:00***	1	***1.4952***	***5.35***	2,174	5.46	1,467	6.84
5.64	6666	10/5 17:00	1	-	**5.96**	6664	***10/5 15:00***	1	***4.2308***	***1.73***	1,555	4.01	991	5.96
5.80	7856	11/24 7:00	1	0.0667	**5.80**	7856	11/24 7:00	1	***0.0765***	***5.79***	1,425	3.10	893	5.87
6.70	8755	12/31 18:00	1	-	**6.87**	8754	***12/31 17:00***	1	***0.2213***	***6.65***	1,853	4.67	1,179	6.87
6.70					**7.13**				4.23		21,991	6.19	14,400	7.55
6.21														

Load/PV System Summary:

Large Customer Monthly kWh	1,500	
Annual Customer Energy (kWh)	18,000	
Annual PV Production-South (kWh)	18,000	Note: Input for annual production in "Rate_PV Input" tab.
Annual PV Production-West (kWh)	15,222	
System Size	10.00	kW-DC
Initial System Cost	$ 17,499.65	

		Day Count	365	31	28	31	30	31	30	31	31	30	31	30	31
				1	2	3	4	5	6	7	8	9	10	11	12
1	**Description**		**Annual**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
2	Energy Use (kWh)		17,998	1,359	1,055	1,029	1,085	1,440	1,968	2,364	2,094	1,846	1,258	1,109	1,391
3	Total Peak Demand (kW)		8.56	7.77	7.34	6.66	7.06	7.80	8.29	8.56	8.15	8.03	6.88	7.02	7.93
4	Ratchet Minimum-Total (kW)		-	-	-	-	-	-	-	-	-	-	-	-	-
5	Net Demand at Peak (kW)		8.42	7.77	7.34	6.66	7.06	7.60	7.83	8.42	7.94	7.95	6.88	7.02	7.93
6	Ratchet Minimum-Net (kW)		-	-	-	-	-	-	-	-	-	-	-	-	-
7	Load Factor (Total Peak)		24.0%	23.5%	21.4%	20.8%	21.3%	24.8%	33.0%	37.1%	34.5%	31.9%	24.6%	21.9%	23.6%
8															
9	Net Hourly Energy Delivered (kWh)		9,648	868	652	566	518	656	937	1,168	1,057	937	663	665	961
10	Net Hourly Energy Received (kBh)		9,650	691	770	1,036	1,103	1,048	784	652	686	709	826	731	614
11															
12	PV Output (kWh)		18,000	1,121	1,204	1,558	1,753	1,868	1,779	1,784	1,692	1,560	1,424	1,188	1,069
13	PV Output (max kW)		8.7	7.1	8.6	8.5	8.3	8.7	8.3	8.3	8.1	8.4	8.0	7.2	7.0
14	Capacity Factor		23.5%	21.3%	20.7%	24.7%	29.3%	28.7%	29.7%	28.8%	28.2%	25.9%	23.8%	22.9%	20.5%
15															
16	Net-Metering Rollover			-	-	149	677	1,346	1,774	1,585	1,006	603	317	483	563
17	Billing kWh			238	-	-	-	-	-	-	-	-	-	-	-
18															
19															

			Loads without DG:					**PV kWh/kBh Data**						
		1	2	3	4	5	6	7	8	9	10	11	12	13
			2014 Solar Billing Dets - 95th percentile			Scaled to:	18,000	**SAM PV scaled**	**Solar House**	**Solar House**	**Solar House**	**SAM PV scaled**	**Scaled**	**Scaled**
			kWh	kW	Load Factor	**kWh**	**kW**	**w/Annual Use**	**total PV out**	**Net kWh in**	**kBh**	**w/Bill Dets.**	**Net kWh in**	**kBh**
31	January	1	1,751	10.01	23.5%	**1,359**	**7.77**	1,334	1,334	1,204	913	1,121	868	691
28	February	2	1,359	9.45	21.4%	**1,055**	**7.34**	1,227	1,433	904	1,018	1,204	652	770
31	March	3	1,326	8.58	20.8%	**1,029**	**6.66**	1,630	1,854	785	1,369	1,558	566	1,036
30	April	4	1,398	9.10	21.3%	**1,085**	**7.06**	1,739	2,087	717	1,458	1,753	518	1,103
31	May	5	1,855	10.05	24.8%	**1,440**	**7.80**	1,730	2,224	909	1,385	1,868	656	1,048
30	June	6	2,535	10.68	33.0%	**1,968**	**8.29**	1,599	2,118	1,299	1,036	1,779	937	784
31	July	7	3,046	11.03	37.1%	**2,364**	**8.56**	1,544	2,124	1,619	861	1,784	1,168	652
31	August	8	2,698	10.51	34.5%	**2,094**	**8.15**	1,583	2,014	1,465	906	1,692	1,057	686
30	September	9	2,378	10.34	31.9%	**1,846**	**8.03**	1,489	1,857	1,299	938	1,560	937	709
31	October	10	1,621	8.86	24.6%	**1,258**	**6.88**	1,475	1,695	918	1,092	1,424	663	826
30	November	11	1,429	9.04	22.0%	**1,109**	**7.02**	1,364	1,415	922	966	1,188	665	731
31	December	12	1,792	10.22	23.6%	**1,391**	**7.93**	1,286	1,272	1,332	811	1,069	961	614
365			23,188	11.03	24.0%	**18,000**	**8.56**	18,000	21,429	13,374	12,754	18,000	9,649	9,649
30.4		Monthly Avg.	1,932	9.82	27.0%		**7.62**			104.9%	13,064		100.0%	9,649

Peak kW Scaling and Adjustments:						**Peak Shifting Analysis:**					**For Scaling 8760:**		**Check:**	
14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
											2014 Res Avg Hrly Profile			
Scaled net kW	Max net kW Hour Position	Max net kW Hour	Count	PV output at Peak	**net kW adj for DG**	Max kW Hour Position	Max kW Hour	Count	DG output at Peak	Max kW less PV	Raw kWh	Raw kW	Scaled kWh	Scaled kW
7.77	127	1/6 6:00	1	-	**7.77**	127	1/6 6:00	1	-	7.77	2,305	4.75	1,359	7.77
7.34	824	2/4 7:00	1	-	**7.34**	824	2/4 7:00	1	-	***7.34***	1,874	4.83	1,055	7.34
6.56	1964	3/23 19:00	1	-	**6.66**	1451	***3/2 10:00***	1	***5.5939***	***1.06***	1,868	3.43	1,029	6.66
6.88	2635	4/20 18:00	1	-	**7.06**	2658	***4/21 17:00***	1	***1.3840***	***5.68***	1,913	4.74	1,085	7.06
6.85	3524	5/27 19:00	1	0.2024	**7.60**	3520	***5/27 15:00***	1	***5.1873***	***2.61***	2,336	6.17	1,440	7.80
7.53	4339	6/30 18:00	1	0.4532	**7.83**	4313	***6/29 16:00***	1	***3.6763***	***4.61***	2,992	6.88	1,968	8.29
7.45	5060	7/30 19:00	1	0.1456	**8.42**	4912	***7/24 15:00***	1	***5.1329***	***3.43***	3,516	7.39	2,364	8.56
7.38	5491	8/17 18:00	1	0.2192	**7.94**	5487	***8/17 14:00***	1	***6.2326***	***1.92***	3,102	7.09	2,094	8.15
7.41	5971	9/6 18:00	1	0.0802	**7.95**	6161	***9/14 16:00***	1	***3.7114***	***4.32***	2,800	6.69	1,846	8.03
6.38	6642	10/4 17:00	1	-	**6.88**	6664	***10/5 15:00***	1	***5.2886***	***1.59***	2,095	5.25	1,258	6.88
7.00	7855	11/24 6:00	1	-	**7.02**	7935	***11/27 14:00***	1	***6.4984***	***0.52***	1,953	4.00	1,109	7.02
7.63	8755	12/31 18:00	1	-	**7.93**	8748	***12/31 11:00***	1	***0.9211***	***7.01***	2,523	6.10	1,391	7.93
7.77					**8.42**				6.50		29,276	7.39	18,000	8.56
7.18														