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IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR APPROVAL OF NET METERING COST SHIFT SOLUTION.	Docket No. E-01345A-13-0248

TASC NOTICE OF FILING COMMENT LETTER IN RESPONSE TO CALIFORNIA E3 DRAFT NET ENERGY METERING COST-EFFECTIVENESS STUDY

The Alliance for Solar Choice ("TASC"), through undersigned counsel, respectfully submits the attached letter prepared by Anne Smart, the Executive Director of TASC, in response to the submission of the California E3 Draft Net Energy Metering Cost-Effectiveness Study.

RESPECTFULLY SUBMITTED this 1st day of November, 2013.

By

Hugh L. Hallman
Hallman & Affiliates, P.C.
2011 North Campo Alegre Road
Suite 100
Tempe, AZ 85281
480-424-3900
Bar No. 12164

Attorney for The Alliance for Solar Choice

CERTIFICATE OF SERVICE

I hereby certify I have this day sent via hand delivery an original and thirteen copies of the foregoing **NOTICE OF FILING COMMENT LETTER IN RESPONSE TO THE SUBMISSION OF THE CALIFORNIA E3 DRAFT NET ENERGY METERING COST-EFFECTIVENES STUDY** on this 1st day of November, 2013 with:

Docket Control
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, Arizona 85007

I hereby certify that I have this day served the foregoing documents via regular mail on all parties of record and all persons listed on the official service list for Docket No. E-01345A-13-0248 on the Arizona Corporation Commission's website:

Arizona Corporation Commission	Janice Alward	1200 W. Washington St. Phoenix, Arizona 85007
Arizona Corporation Commission	Steve Olea	1200 W. Washington St. Phoenix, Arizona 85007
Arizona Corporation Commission	Lyn Farmer	1200 W. Washington St. Phoenix, Arizona 85007
Pinnacle West Capital Corporation	Thomas Loquvam	400 N. 5th St, MS 8695 Phoenix, Arizona 85004
	Lewis Levenson	1308 E. Cedar Lane Payson, Arizona 85541
	Patty Ihle	304 E. Cedar Mill Rd. Star Valley, Arizona 85541
TEP, Co. and UNS Electric, Inc.	Michael Patten Jason Gellman	Roshka, DeWulf & Patten, PLC 400 E. Van Buren St., Ste. 800 Phoenix, Arizona 85004
Arizona Competitive Power Alliance; Water Utility Association of Arizona	Greg Patterson	Munger Chadwick 916 W. Adams St. Ste. 3 Phoenix, Arizona 85007
RUCO	Daniel Pozefsky	1110 West Washington Street Suite 220 Phoenix, Arizona 85007
TEP Co.	Bradley Carroll Kimberly A. Ruht	88 E. Broadway Blvd. MS HQE910 P.O. Box 711 Tucson, Arizona 85702
Arizona Solar Deployment Alliance	Garry Hays	1702 E. Highland Ave., Suite 204 Phoenix, Arizona 85016

Grand Canyon State Electric Cooperative Assoc., Inc.	John Wallace	2210 South Priest Dr. Tempe, Arizona 85282
	Tim Lindl	Keyes, Fox & Wiedman LLP 436 14th St., Suite 1305 Oakland, CA 94612
The Alliance for Solar Choice	Kevin T. Fox	Keyes, Fox & Wiedman LLP 436 14th St., Suite 1305 Oakland, CA 94612
The Alliance for Solar Choice	Anne Smart	45 Fremont Street, 32nd Floor San Francisco, California 94105
Solar Energy Industries Association	Todd Glass	Wilson Sonsini Goodrich & Rosati, PC 701 Fifth Ave., Suite 5100 Seattle, Washington 98104
Solar Energy Industries Association	Court S. Rich	Rose Law Group 6613 N. Scottsdale Rd., Ste. 200 Scottsdale, Arizona 85250
Interstate Renewable Energy Council, Inc.	Giancarlo Estrada Estrada Legal, P.C.	1 E. Camelback Rd., Suite 550 Phoenix, AZ 85012
Interstate Renewable Energy Council, Inc.	Erica M. Schroeder	Keyes, Fox & Wiedman LLP 436 14th St., Suite 1305 Oakland, CA 94612
Western Resources Advocates; Vote for Solar Initiative	Timothy M. Hogan	202 E. McDowell Rd., Suite 153 Phoenix, AZ 85004
Western Resource Advocates	David Berry	P.O. Box 1064 Scottsdale, AZ 85252-1064
Arizona Solar Energy Industries Association	Mark Holohan	2221 W. Lone Cactus Dr., Suite 2 Phoenix, Arizona 85007
Sun City West Property Owners and Residents Assc.	W.R. Hansen	13815 W. Camino del Sol Sun City West, Arizona 85375

Dated this 1st day of November, 2013.

By

Hugh L. Hallman
Hallman & Affiliates, P.C.
2011 North Campo Alegre Road
Suite 100
Tempe, AZ 85281
480-424-3900
Bar No. 12164

Attorney for The Alliance for Solar Choice

THE ALLIANCE FOR SOLAR CHOICE

October 28, 2013

Arizona Corporation Commission
Docket Control Office
1200 W. Washington Street
Phoenix, Arizona 85007

Re: Docket No. E-01345A-13-0248: The Alliance for Solar Choice Letter to Docket.

The Alliance for Solar Choice ("TASC") strongly objects to the September 30, 2013 introduction of the California E3 Draft Net Energy Metering Cost-Effectiveness Study ("E3 Study") into this docket. On numerous occasions, TASC has highlighted the lack of rate case-quality, cost of service information that is necessary to justify any of the inconsistent and conflicting rates, charges and customer classifications that have been proposed in this proceeding.

Injection of the E3 Study into the docket only further muddies an inadequate and inconsistent record. In fact, the only reasonable conclusion that can be drawn upon the present record is that parties fundamentally disagree on the methodology that should be used to measure the costs and benefits of distributed solar. TASC accordingly agrees with the October 1, 2013 Utilities Division Staff Report issued in this docket, which concludes that "the objective value aspects of DG to the APS system can best be determined in the context of a general rate case when all of APS's costs can be considered." *See* Staff Report at p. 6.

Setting aside the fact that the E3 Study is California-specific and therefore cannot reasonably form the basis for any result reached in this docket, the E3 Study also has received widespread criticism due to the numerous errors it contains. We point out a number of flaws with the E3 Study in the letter below. However, to provide the Commission a full view of the numerous errors contained in the E3 Study methodology, TASC attaches to this letter protests submitted to the California Public Utilities Commission on October 10, 2013 by TASC and the Vote Solar Initiative. We provide this information to assist the Commission's understanding of the E3 Study. However, we reiterate our belief that a California study cannot reasonably form the basis for the proper ratemaking treatment of net metering in Arizona.

The E3 Study wrongly included energy used onsite, even though that energy never touches the grid and does not impact other ratepayers. The scope of a cost-benefit analysis of net metering should be limited to the power that is exported to the grid from net-metered systems. The analysis should not include the output from behind-the-meter generation that serves the customer's onsite load. A customer using solar panels to serve onsite electricity needs should be treated no differently than a customer that turns the lights off or installs energy-efficient appliances. Net metering is a bill credit that a customer receives for power exported to the grid, and thus a study of the impacts of net metering should be based only on exports. Studies that look at the value of distributed solar more generally, as opposed to net metering policy specifically, will look beyond exports at all generation; however, the E3 Study focused on net metering and so should focus only on exports only.

The E3 Study uses outdated 2011 rate structures despite significant recent changes to residential rates. Throughout the draft study, E3 notes that rate design plays a fundamental role in the calculations and that changes to rate design could have substantial impacts on the study's results. Nevertheless, to calculate NEM customer bill savings, E3 utilized outdated 2011 rates. E3 should have used current rate structures given that net metering costs are directly tied to rate levels. Moreover, rate structures are expected to change significantly in the near future as a result of enactment of recent legislation that removes caps on lower-tier rate increases and authorizes new fixed charges. As a result, all of the E3 NEM Study results are already out of date and will become even more so with coming rate reform.

The E3 Study fails to fully value the 100% renewable content of net-metered generation and exports. Instead, the analysis values net-metered generation as comparable only to the 20% to 33% renewable grid power that NEM generation displaces. California's utilities have argued in their shared renewables applications that there is an additional ratepayer cost associated with going beyond a 33% renewable penetration. Recent changes in California law also allow the State's Public Utilities Commission to require utilities to procure renewables in excess of existing RPS targets, making it reasonable to assume that there is value to renewables in excess of what is now a 33% RPS minimum requirement. Numerous parties requested that the E3 Study include a sensitivity valuing net-metered generation as 100% renewable in all years, but E3 did not include such an analysis.

The E3 Study fails to include savings in high-voltage transmission costs for two of the state's investor-owned utilities. California policy encourages distributed solar generation in significant part to reduce the need for new high-voltage transmission lines. Yet the E3 analysis of the benefits of net-metered solar omits savings from the reduced need for high-voltage transmission lines for Southern California Edison and San Diego Gas & Electric. Past studies in California have shown that customer-site solar systems reduce peak demand on the transmission system on at least a one-for-one basis, make additional capacity available, and thus avoid future transmission line expansion costs. The omission of these savings is a significant defect in the E3 analysis.

The E3 Study fails to include the societal costs and benefits of net-metered generation. As a cornerstone policy enabling the growth of rooftop solar, net metering creates a host of societal benefits for all Californians, including public health benefits, employment and downstream economic effects, market price impacts, grid security benefits, and water savings. No study of the impacts of net metering is complete without the inclusion of societal benefits. However, the E3 NEM Study excludes societal benefits from consideration.

For a list of our additional concerns with the E3 Study, please see the attached comments that were provided to the California Public Utilities Commission Energy Division by TASC and the Vote Solar Initiative on October 10, 2013.

Respectfully submitted this 28th day of October, 2013.

AnneSmart

Anne Smart
Executive Director
The Alliance for Solar Choice
45 Fremont Street, 32nd Floor
San Francisco, CA 94105
Phone: (415) 580-6900
E-mail: anne@allianceforsolarchoice.com

ATTACHMENT 1

The Alliance for Solar Choice
Oct 10, 2013 Comments to CPUC Energy Division
Highlighting Errors in E3 NEM Study

Comments of The Alliance for Solar Choice on the E3 Draft Net Energy Metering Cost-Effectiveness Study

The Alliance for Solar Choice (TASC) submits these comments pursuant to a September 26, 2013 e-mail from Ehren Seybert of the CPUC Energy Division. Energy Division asked that parties provide comments on apparent errors in the draft net energy metering cost-effectiveness analysis (Draft NEM Study), developed by the Energy and Environmental Economics consulting firm (E3) and released on September 26, 2013.

In providing these comments, TASC notes that there are a number of areas where the E3 analysis is "black box", precluding robust stakeholder review. In particular, E3 has not released or made available the underlying SAS data and analyses used to create NEM profiles for each NEM customer included in the analysis. This information is a fundamental component of the overall analysis but is largely inaccessible to stakeholders. Similarly, E3 has not made the underlying data available regarding distribution system loading, again confounding stakeholders from assessing the reasonableness of the results related to avoided T&D costs. While confidentiality issues may need to be addressed, we request this data be made available under a confidentiality agreement, at least to non-market participants to the extent the information is subject to the Commission's confidentiality rules.

a. The Scope of the Analysis Should Be Limited to Exports-Only.

The scope of a cost / benefit analysis of NEM should be limited to the power that is exported to the grid from NEM systems, and should not include the output from behind-the-meter generation that serves the customer's onsite load. Longstanding federal law (PURPA) and the California policies implementing that law allow a customer to install on-site renewable generation that is interconnected to the grid and serves on-site load, even without NEM. Net metering concerns the bill credit that a customer receives for power exported to the grid from a system, and thus the costs and benefits of NEM should be based only on an analysis of exports. As a result, while we acknowledge that Assembly Bill 2514 (Bradford, 2012) required all-output results be included in the study, we dispute the relevancy of those results in the Draft NEM Study.[1]

b. Results Are Highly Suspect Due to Reliance on Outdated Rates.

To calculate NEM customer bill savings, E3 utilized 2011 rates.[2] At the same time, throughout the draft study, E3 qualifies its analysis by noting that rate design plays a fundamental role in the calculations, and that changes to rate design could have substantial impacts on the study's results.[3] In light of this, and the fact that there have been significant changes to residential rates since 2011, we request that more current rate structures, specifically those that are currently in place, be used in the final study rather than the now outdated 2011 rates. While rate structures are expected to change significantly in the future as a result of enactment of AB 327, which removes caps on lower-tier rate increases and authorizes fixed charges up to $10 for non-CARE customers, we believe current rates

1 See page 2 of "Comments of the Solar Energy Industries Association, Vote Solar Initiative, Sierra Club California, and California Solar Energy Industries Association on the Scope of Work for the CPUC/E3 Net Energy Metering Study," submitted to Energy Division November 5, 2012 ("Joint Parties Comments").

2 See page 43 of Draft NEM study.

3 See, for example, pages 3-4 of the Draft E3 Study, which states, "...changes to the tiered rates would have a significant impact on the study results. Similarly, differences in retail rates should be an important consideration for policymakers outside of California that are using this study."

are likely to be more reflective of the general direction of rate design relative to the 2011 rates on which the study relied.

c. NEM Generation Should Be Valued at 100% of Renewable Premium.

The Draft NEM Study fails to fully value the 100% renewable content of NEM output and exports, compared to the 20% to 33% grid power that NEM generation displaces. For several reasons, we continue to recommend that the final study include a sensitivity valuing net-metered generation at 100% of the renewable premium in all years.[4] First, net-metered generation replaces grid power (of which only a fraction is renewable) with 100% renewable generation. Second, the utilities themselves have argued in their shared renewables applications at the Commission that there is an additional ratepayer cost associated with going beyond a 33% renewable penetration. Finally, with the enactment of AB 327, the Commission is authorized to require utilities to procure renewables in excess of existing RPS targets, making it reasonable to assume that there is value to renewables in excess of what is now a 33% RPS minimum requirement. Therefore, we request that the final study include two additional sensitivities: first, a sensitivity assuming that the RPS is raised to 50% by 2030, and, second, a sensitivity assuming all NEM output is fully valued as 100% renewable.

d. The Study Fails to Show Participant Impacts as Required by AB 2514.

The Draft NEM Study looks only at impacts from the perspective of non-participating ratepayers, in conflict with the statutory requirements pursuant to AB 2514, which requires the Commission to provide an analysis of NEM from the perspective of participating ratepayers in addition to non-participating customers.[5] We request that this analysis be included in the final study.

e. The Study is Inconsistent with the Commission's Standard Practice Manual.

In evaluating the costs and benefits of customer side programs, the Commission's Standard Practice Manual identifies four tests, each of which quantifies the costs and benefit that can be attributed to a given program or resource from various perspectives.[6] The cost-benefit analysis performed by E3 is confined to the Ratepayer Impact Measure (RIM) Test, looking exclusively at the costs and benefits from the standpoint of non-participating customers. This should not be the only perspective considered. In the context of the Commission's energy efficiency programs, the tests used to determine whether the benefits exceed costs and whether the IOUs' multi-billion dollar energy efficiency portfolios should be approved are the Total Resource Cost (TRC) Test and the Program Administrator Cost (PAC) Test, both of which encompass a broader, and, for policy-making purposes, more reasonable set of costs and benefits. In the final study, E3 should at a minimum include results from a Participant Test; combining this with the non-participant study results will provide the Commission with all the information it needs to perform a Total Resource Cost ("TRC")

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4 See pages 4-5 of Joint Parties Comments and pages 2-3 of "Reply Comments of the Sierra Club and Vote Solar Initiative on the Scope of Work for the CPUC/E3 Net Energy Metering Study," submitted to Energy Division November 15, 2012.

5 See PUC code section 2827.1 which states "The study shall quantify the costs and benefits of net energy metering to participants and nonparticipants and shall further disaggregate the results by utility, customer class, and household income groups within the residential class."

6 See California Standard Practice Manual; http://www.cpuc.ca.gov/NR/rdonlyres/004ABF9D-027C-4BE1-9AE1-CE56ADF8DADC/0/CPUC_STANDARD_PRACTICE_MANUAL.pdf

test, which is considered an important approach in the analysis of the cost-effectiveness of demand-side programs.[7]

f. The Study Should Include Societal Costs and Benefits.

The final study should assess not just ratepayer costs and benefits of NEM, but should include societal costs (if any) and benefits associated with NEM systems as well. These societal benefits are explicitly excluded from consideration in the Draft NEM Study. In comments to Energy Division on June 5, 2013, TASC, Vote Solar and a host of public health, conservation and environmental justice groups supported developing a comprehensive Societal Cost Test and applying it to customer-sited DG resources and to the NEM program.

g. The Study Should Not Include a Resource Balance Year (RBY) in the Base Case.

The final study should not include a Resource Balance Year (RBY) in the Base Case. In other words, the study should assume long-run avoided costs in all years, rather than shifting from short-run to long-run avoided costs at a future RBY. In D. 10-12-024, the Commission rejected the use of the RBY concept for evaluating demand response resources, finding that the use of long-run avoided costs in all years was consistent with the status of DR as a preferred resource in the state's loading order for electric resources. Renewable distributed generation (DG) is also a preferred resource, and the logic and precedent of D. 10-12-024 should be extended to renewable, net-metered DG as well.[8]

h. The Study Should Use Existing Methods to Allocate Generation and Distribution Capacity Costs.

E3 uses a method to allocate generation capacity that has not been vetted with stakeholders in a DG proceeding, or perhaps even with non-IOU stakeholders. Although the Final SOW indicated that E3 might use a new allocation method ("if time allows" – page 13), no details about the approach were provided except that it would be an "ELCC model" (page 18). TASC is not a participant in the demand response (DR) proceeding where this method apparently was developed. The two weeks since the draft NEM Study was issued have not provided enough time to review in any detail the new E3 "Capacity Planning Model." We are unsure whether non-IOU parties were involved in the model's development; the Draft NEM Study only states, at page C-35: "E3 has held numerous meetings with the IOU subject matter experts on the model, and the model has been released to the utilities for their review." TASC urges the Energy Division to retain the transparent 250-hour method that E3 used previously. At a minimum, sensitivities need to be run to show how the old and new allocation models impact the study's results. Finally, as noted below, the 250-hour method also is more consistent with E3's approach to allocating distribution capacity costs.

TASC observes that E3's new model for allocating generation capacity costs is based on loss-of-load probability (LOLP) modeling that does not use total system load, but instead uses load net of must-take renewable resources (see page C-35). We question why only renewable resources are treated as a deterministic subtractor to load; correctly representing the impact of these intermittent resources on the reliability of the system would seem to require a stochastic treatment, just like the probabilistic treatment of conventional resources that are sometimes forced out. E3's method using loads net of solar appears to create artificially low net loads (and thus low LOLPs) during the

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7 See page 1 of Joint Parties Comments and pages 3-5 of "Comments of the interstate Renewable Energy Council on E3's Proposed Scope of Work Regarding Net Energy Metering Cost-Effectiveness," submitted to Energy Division November 5, 2012.

8 See pp.8-9 of Joint Parties Comments.

afternoon hours when solar generation is high. For example, baseload nuclear and QF units also are non-dispatchable must-take generation; why shouldn't these units be subtracted from total load to determine net loads?

E3 also has a new model for allocating distribution capacity costs that is based on an analysis of utility data on distribution substation load shapes. The model has not been vetted previously, although the technique E3 uses is familiar. The new allocation method uses a peak capacity allocation factor (PCAF) approach that is similar to the 250-hour peak hour allocation method that E3 is no longer using to allocate generation capacity costs. We also note that PG&E has long used the PCAF method to allocate peak-related costs, including generation capacity costs. It is unclear why the 250-hour method is unsuitable for generation capacity but a similar approach is fine for distribution capacity. Further, the substation load data is confidential, and if it is from 2011, it could be dominated by the September heat wave (see Appendix D, Figure 1). It is not clear whether this allocation was normalized to a TMY.

Finally, E3 has not provided any details on how it aggregated the allocators for individual substations into the allocators for climate zones used in the avoided cost model. The majority of NEM customers for PG&E and SCE are commercial & industrial whose loads tend to peak in the mid-afternoon (see Table 9); it is residential circuits that peak in the evening. Thus, it is not clear why the allocation of distribution capacity costs serving NEM customers should be shifted later in the day compared to the allocation of generation capacity. We have aggregated the distribution capacity allocators, and this allocation peaks later in the day than the generation capacity allocation. TASC does not understand why an aggregate allocation of distribution capacity over all climate zones should differ significantly from the generation capacity allocation.

i. CARE Customers Should Be Excluded From The Analysis of NEM Participation by Household Income.

The E3 analysis compares the median household income of customers that have NEM systems with the median household income of all IOU customer households, as well as all California households, including CARE customers. We believe a more appropriate comparison would be between households that have solar and non-CARE households given that CARE rates are heavily subsidized and thus have very limited financial incentive to go solar. In other words, limited uptake of solar among lower income households is driven in no small part by the fact that solar does not make economic sense for the vast majority of CARE customers on subsidized rates. Because CARE customers represent about 30% of the IOUs' residential customers, excluding them from the calculation of the IOUs' median household income would raise this substantially, resulting in a much smaller gap in terms of the relative incomes of those that have NEM systems and those that do not.

j. Residential Minimum Bill Impacts Should Be Included.

E3 ignores the minimum bills paid by NEM residential customers. See page B-7: "Bill calculations do not include any minimum charges. Minimum charges are common for residential customers, but their values are small and do not significantly impact the total annual bill amount." This may not be correct, as it is our understanding that minimum bills are paid every month by every NEM residential customer who is on annual billing, even if they have a positive bill credit balance for that month (as E3 admits on page B-3). Residential NEM customers on annual billing only pay their accumulated credit balance once each year, so they are subject to the minimum bill each month. These minimum charges are significant; the following table shows what they would be on an annual basis if all NEM customers were on annual billing (we do not know what % of NEM customers are on monthly vs. annual billing).

Utility	Number of 2011 Residential NEM Customers	Annual Minimum Bills	Total
PG&E	70,000	$54	$3,780,000
SCE	24,000	$22	$530,000
SDG&E	17,000	$62	$1,050,000
TOTAL	110,000		$5,360,000

Given that when the 5% NEM cap is reached there could be five times more NEM customers than shown in this table, the minimum bill revenues could be as much as $25 million per year for residential NEM customers. This would be a significant factor in reducing NEM costs.

k. The Return of GHG Allowance Revenues Should Be Recognized.

The Draft NEM Study says GHG costs are a "key input" of retail rate escalation (pages B-12 and B-13). This ignores the fact that residential and small commercial customers are protected from increased costs due to GHG regulation by the return of GHG allowance revenues, as adopted by the Commission in D. 12-12-033. Residential customers will even receive a "climate dividend." E3 appears to have based its rate escalation on a 2010 LTPP model, which pre-dates and does not include the Commission's subsequent policy orders on the return of GHG allowance revenues to residential customers.

l. Additional Items Addressed in Detail in Comments By the Vote Solar Initiative:

In an effort to keep these comments within the page limit requested by Energy Division, TASC addresses in full only a subset of our concerns. In addition, we fully concur with the additional and distinct concerns raised by The Vote Solar Initiative in comments on the Draft NEM Study that they submitted on October 10, 2013, including the following:

- The study should highlight annual NEM impacts based on the 20-year analysis.
- Vintaging of ELCC's should be clarified and included in the base case.
- Results should be reported by rate schedule in the body of the study.
- The study should include avoided high-voltage transmission costs. Notably, by excluding these avoided costs, the E3 study is actually more conservative than a similar analysis conducted by SDG&E.[9]
- The study should use updated marginal costs from utility general rate cases and use those costs consistently across the avoided cost model and cost-of-service study.
- A spreadsheet error in the allocation of capacity costs should be fixed.
- There is an apparent error in the "high case" capacity costs in Figure 15.
- SONGS should be removed from the Resource Balance Year Calculation.
- Market heat rates should use post-SONGS values.

TASC appreciates the opportunity to present these comments on errors and other issues we have identified in the Draft NEM Study. We look forward to reviewing a Final Study that addresses these issues.

[9] San Diego Distributed Solar PV Impact Study, at 48-49, Tables 19-20.

Respectfully submitted this 10th day of October, 2013.

Anne Smart

Anne Smart
Executive
Director
The Alliance for Solar
Choice 595 Market
Street, 30th Floor San
Francisco, CA 94105
Phone: (415) 580-6900
E-mail: anne@allianceforsolarchoice.com

ATTACHMENT 2

Vote Solar Initiative
Oct 10, 2013 Comments to CPUC Energy Division
Highlighting Errors in E3 NEM Study

Comments of the Vote Solar Initiative On Errors in the Draft E3 Net Energy Metering Study

1. Introduction

The Vote Solar Initiative (Vote Solar) appreciates this opportunity to submit comments on apparent errors in the draft cost/benefit analysis of net energy metering (Draft NEM Study) in California, requested by CPUC and performed by the Energy and Environmental Economics (E3) consulting firm and released on September 26, 2013. Vote Solar submits these comments in accordance with the e-mail of September 26, 2013 from Ehren Seybert of the CPUC Energy Division. Vote Solar appreciates the significant effort that E3 and Energy Division have put into the Draft NEM Study, and provides these comments in an effort to correct certain mistakes in the draft and to contribute to a more accurate final NEM Study.

Vote Solar has identified a considerable list of concerns with the Draft NEM Study's scope, methodology, inputs and calculations. In an effort to keep these comments within the 5-page limit requested by Energy Division, Vote Solar addresses in full only a subset of these concerns. In addition, we fully concur with the additional and distinct concerns raised by The Alliance for Solar Choice (TASC) in the comments on the Draft NEM Study which they submitted to Energy Division today, including the following:

- The scope of the analysis should be limited to exports-only.
- Results are highly suspect due to reliance on outdated rates and anticipated rate reform.
- NEM generation should be valued at 100% of the renewable premium.
- The study fails to show participant impacts as required by AB 2514, is inconsistent with the Commission's Standard Practice Manual, and should include societal costs and benefits.
- The study should not use a Resource Balance Year (RBY) in the Base Case.
- The study should use existing methods to allocate generation and distribution capacity costs.
- CARE customers should be excluded from the household income analysis.
- Residential minimum bill impacts should be included.
- The return of GHG allowance revenues should be recognized.

2. Errors in the Draft NEM Study

a. Comparison of 2010 and 2013 Results / Use of Lifecycle Costs

The draft report's de-emphasis of the 20-year lifecycle results is incorrect and misleading, given that renewable DG is a long-term resource. Reporting the value of all net metered DG on the basis of a future year "snapshot" in 2020 does not fully capture solar's value as a hedge against future increases in fossil fuel prices and the costs to mitigate GHG emissions.

The Executive Summary does not present results for the 20-year lifecycle analysis. This is misleading when compared to the Executive Summary of the 2010 report, which only reported 20-year lifecycle results. E3 should highlight annual NEM impacts based on the 20-year analysis, not for the 2020 "snapshot," so that the results of the 2010 and 2013 NEM reports can be directly compared on an apples-to-apples basis. The new study's results for the 20-year lifecycle analysis are buried in Table 40, and show smaller impacts than the 2010 study at full CSI build-out. Only on page 78 does E3 note that the full CSI impacts are smaller in this study than in the 2010 work.

On a 20-year lifecycle basis, NEM impacts at the full 5% NEM cap are $236 million per year, much lower than the 2020 snapshot of $359 million, and just 0.68% of the revenue requirement, not 1.03%.

b. Need to Report Results by Rate Schedule in the Body of the Study

The Draft NEM Study does not report results by rate schedule. Doing so is particularly important since the Commission is considering significant changes to residential rates in R.12-06-013. Stakeholders in that proceeding have proposed changes to residential rates including moving residential customers gradually to default time-of-use rates. It would be very useful for policymakers and stakeholders to see how NEM impacts vary by rate schedule. E3 provides results by rate schedule in the NEM Summary Tool workpapers in the form of detailed results for over 9,000 "bins," but those results must be aggregated by rate schedule and included in the study itself as many readers will not be able to extract them from the workpapers. Furthermore, the draft report does not comment on how the results were impacted by the reductions in upper tier rates from the 2008 rates used in the 2010 study to the 2011 rates used in the new work.

c. Failure to Include Avoided High-Voltage Transmission Costs

The Joint Solar Parties commented last fall that the E3 avoided cost model fails to include avoided CAISO-jurisdictional high-voltage transmission costs for Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E), even though these investor-owned utilities (IOUs) have calculated these marginal costs, and E3 included all other IOU marginal T&D costs for sub-transmission and distribution. Pacific Gas & Electric's (PG&E) marginal transmission costs include CAISO-level costs. E3's response in the December 2012 Final SOW was that the avoided costs used in the NEM Study would include "[c]onsideration of FERC-jurisdictional transmission costs at the CAISO." E3's Snu Price acknowledged at the September 27 workshop that these avoided transmission costs still are not included in the E3 avoided cost calculator, and page C-44 states that "[t]ransmission avoided costs are for subtransmission or area transmission assets "downstream" of the CAISO." In contrast, Vote Solar notes that the recent draft San Diego Solar DG study included such avoided CAISO-level transmission costs for SDG&E.[1]

Behind-the-meter DG clearly provides significant output in peak periods, when the transmission system peaks, serving both on-site loads (where the power never touches the grid) and for export to the distribution system (where the power serves nearby distribution loads without using the transmission system). Past impact evaluation reports for the CSI have shown that CSI systems reduce peak transmission system loadings on at least a one-for-one basis, make additional capacity available on the transmission system, and thus avoid transmission expansion costs.[2] A major policy reason for the state's <u>distributed</u> generation programs is to avoid the need for more bulk transmission lines.[3]

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[1] San Diego Distributed Solar PV Impact Study, at 48-49, Tables 19-20.

[2] Itron, *2009 CSI Impact Evaluation Report*, at page ES-17. Also, Itron, "CPUC Self-Generation Incentive Program – Sixth Year Impact Evaluation Report" (August 30, 2007), at 5-29 to 5-33. These Itron reports are available on the CPUC website at http://www.cpuc.ca.gov/PUC/energy/Solar/evaluation.htm and http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/sgipreports.htm.

[3] For example, the California Energy Commission's *2009 Integrated Energy Policy Report (IEPR)*, at pages 8 and 95) recognized the importance of DG as an alternative to investments in T&D infrastructure, stating "*[b]ecause the*

SCE's most recent GRC (A. 11-06-007) shows a marginal cost for CAISO-controlled transmission of $59.18 per kW-year (2012 $).[4] The draft San Diego Solar DG study used a marginal cost of CAISO transmission for SDG&E of $102.83 per kW-year, escalating at 3% per year.[5] Because demand on the CAISO grid peaks coincident with system demand, these avoided CAISO transmission costs should be allocated in the same manner as generation capacity costs, as was done in the draft San Diego Solar DG study.

d. Failure to Use Updated GRC Marginal Costs, and Inconsistency between Avoided Cost and Cost-of-Service Models

E3 stated in the Final SOW that its study would use "the most recently available marginal cost estimates." This was in response to a comment from the Joint Solar Parties that the SCE and SDG&E avoided T&D values in the E3 model were not based on their latest general rate case filings (A. 11-06-007 and A. 11-10-002). E3 should update these costs to SCE's and SDG&E's most recently-filed 2011 marginal T&D costs, as summarized in the table below. The values in parentheses show the values apparently used in the E3 avoided cost calculator. PG&E's avoided distribution costs are based on their 2011 general rate case values.

Table 1: *SCE and SDG&E Marginal T&D Costs (2012 $/kW-year) from Current GRCs*

Marginal T&D Cost Category	SCE	SDG&E
Distribution	91.37 *(30.10)*	74.06 *(52.24)*
Substation		27.85 *(21.08)*
Sub-transmission	35.06 *(23.39)*	
Sources:	*A.11-06-007, Exhibit SCE-2, at 30 (Table I-13) and SCE Workpapers, "MCCR" sheet, "Input Sheet" tab, cells D17-D19.*	*A. 11-10-002, Chapter 6, Tables RME-01 and RME-02.*

More generally, the avoided cost model uses E3's own evaluation of SCE's and SDG&E's marginal distribution costs, rather than using these utilities' marginal distribution costs from their most recent GRCs, shown in the table above. It is also not clear whether E3's Cost-of-Service analysis used SCE's and SDG&E's most recent GRC marginal costs, or some other utility estimates provided in data responses to E3 and which have never been publicly vetted. Only the PG&E marginal distribution costs from its GRC appear to have been used consistently in both portions of the E3 study. However, even for PG&E, the avoided cost model uses PG&E's marginal transmission costs from its GRC, while the Cost-of-Service model uses its filed average transmission rate (based on the recommendation of "a PG&E rates expert" – page D-16). **The E3 study would be greatly improved through the use of a single set of marginal T&D costs from the most recent IOU GRCs, used consistently in both the avoided cost model and the Cost-of-Service study.** The confusion of the reader is only magnified by footnote 35 in Appendix C, which states that "T&D avoided costs provided for the NEM report are not included in the updated avoided cost spreadsheet tool," which suggests that the avoided cost model provided to the parties does not include the actual avoided T&D values that E3 used.

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generation is located near the location where it is needed, distributed generation reduces the need to build new transmission and distribution infrastructure and also reduces losses at peak delivery times."

4 A.11-06-007, SCE Workpapers, "MCCR" sheet, "Input Sheet" tab, cells D17-D19.

5 San Diego Distributed Solar PV Impact Study, at 48, Table 19.

e. Spreadsheet Error in the Allocation of Capacity Costs

E3 made a spreadsheet error that shifts its generation capacity values one hour later into the afternoon. This has a significant impact in reducing solar's capacity value. We do not know whether the same error exists for the allocation of T&D capacity costs, as those are hard-wired numbers.

Column "AK" of the "Hourly Allocation" tab in the avoided cost model makes use of Excel's "Offset" function to gather the hourly capacity allocators from the "Capacity Allocation" tab of the model. However, the row offset variable in the function needs to be rounded to the nearest integer (i.e. hour) so that Excel does not look up the value for the preceding hour (for example, Excel will look up hour 1 when the variable equals 1.999999…). The problem can be fixed by changing the formula to ensure the correct hour is referenced, by rounding the "24 x (current datetime – start datetime)" term to the nearest integer. Thus, for example, the formula in Cell AK7 could be changed as indicated below:

```
OFFSET('Capacity Allocation'!$D$2,ROUND((C27- $C$27)*24,1),MATCH(StartYear,'Capacity Allocation'!$D$1:$AU$1,0)-1)
```

This one-hour shift in the capacity allocation appears to be a significant error, and it incorrectly reduces the capacity value of solar PV. For example, in 2012 the model notes that the 2012 marginal solar ELCC is 49% (i.e. see cell G20 of the "Avoided RPS: tab.). We observe that fixing the lag problem identified above indeed results in a 2012 capacity-allocation-weighted average solar output equal to 49% (i.e. sumproduct of columns AH and AK in the hourly tab). Without the correction, however, the value is 35%. Thus, the model is incorrectly de-rating the ELCC for solar PV by almost 30% (0.35/0.49), due to this spreadsheet error.

For 2020 the results are even more extreme: the RPS tab indicates a 32% ELCC; however, the sumproduct of the solar output (column AH) and the allocators (column AK) is 18%. Thus, the advertised ELCC is 78% above the value actually used. The four figures in Figure A1 of the attached Appendix A provide two examples illustrating the problem with the incorrectly lagged allocation factors: solar PV output is less correlated with the most important "capacity allocation" hours if that allocation is incorrectly lagged one hour later in the day.

f. High Case Avoided Capacity Costs in Figure 15

Figure 15 on page 62 showing the Base, High, and Low sensitivity scenarios appears to show that the High Case (with a 2007 resource balance year and 2013 ELCCs) has a lower avoided capacity costs (the dark red stripe) than the other two cases. This does not make sense, as the changes made in the High Case should increase avoided capacity costs. We have not had the time needed to determine the source of this apparent error.

g. Vintaging of ELCCs Should Be Clarified and Included in the Base Case

Vote Solar was unable to find a means to vintage the ELCCs used in the avoided cost model, as E3 states that it did for the High Case (Table 8). It is unclear if E3 assigned the 2013 ELCC to all NEM systems in the High Case, or assigned to each NEM system the ELCC for the year in which it was installed. This point should be clarified.

ELCCs should be vintaged in the Base Case, not just in the High Case, because many NEM systems were installed long before the state committed to major RPS solar capacity. This issue was not discussed in the scoping comments, as the details of E3's new allocation of generation capacity costs was not known. A NEM system should receive the ELCC of the year in which it enters service (or of the first year of the analysis if it was installed many years earlier). Otherwise, the capacity value of short-lead-time DG resources is reduced by central station capacity that may (or may not) come on-line years later.

h. Removal of SONGS from the Resource Balance Year (RBY) Calculation

SCE announced in June that the SONGS nuclear units will close permanently. Based on Table 7 in Appendix C, removing the SONGS capacity will advance the RBY from 2017 to 2016. Although Vote Solar does not agree with the RBY concept, if it is used the RBY should be 2016.

i. Market Heat Rates Should Use Post-SONGS Values

The draft report notes (at Table 20, page 55) that forward market heat rate projections were taken from the 2010 CPUC Long Term Procurement Plan. The model shows a 8,377 Btu/kWh market heat rate in 2012 but, for 2013 to 2020, it interpolates between an average 2007-2012 heat rate (7,739 Btu/kWh) to a 2020 heat rate equal to 7,438 Btu/kWh, which is then held constant. Given that SONGS is now permanently out of service, and that the 2007-2012 heat rate includes SONGS in every year except 2012, it is incorrect to show heat rates dropping sharply from 2012 to 2013. Actual market heat rates in 2013 to date have averaged about 8,200 Btu per kWh (with GHG costs removed), so the sharp drop in heat rates which E3 assumed in 2013 in Figure 13 of Appendix C has not occurred. It would be more reasonable to simply extend the 2012 market heat rate into the future with a slow decline as more efficient gas-fired resources are added.

At page C-22, E3 states that "while the composition of the generation fleet may change due to increased renewable energy injected into the grid, we do not expect the heat rates of the dispatch units on the margin to change substantially. Accordingly, the rate of increase after 2013 is driven almost exclusively by the forecast change in natural gas prices (see Figure 10)." We agree, but think that the correct number for avoided energy costs should reflect post-SONGS-closure market heat rates. In saying that market heat rates will not "change substantially," E3 appears to be referring to 2020 vs. the 2007-2012 average (i.e. 7,438 vs.7,739 Btu/kWh, respectively). However, this ignores that market heat rates increased sharply from 2011 to 2012 due to SONGS being offline (as shown by the spike in market heat rates in 2012 that is in E3's Figure 13). The increase in market heat rates resulting from the loss of SONGS is a substantial change, and that increase has persisted through 2013 to date. Figure A2 in Appendix A of these comments illustrates the numbers, with the red line indicating Vote Solar's proposed revision to the market heat rates.

Vote Solar appreciates the opportunity to present these comments on the errors that we have identified in the Draft NEM Study. We look forward to reviewing a Final Study which addresses these concerns.

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R. Thomas Beach, Principal,
Crossborder Energy, Consultant to Vote Solar
E-mail: tomb@crossborderenergy.com

_________/s/__________
Susannah Churchill
Solar Policy Advocate, Vote Solar
Email: susannah@votesolar.org

Appendix A: Vote Solar Comments on Errors in E3 Net Energy Metering Study

Figure A1: Spreadsheet Error Shifting Capacity Values to One Hour Later

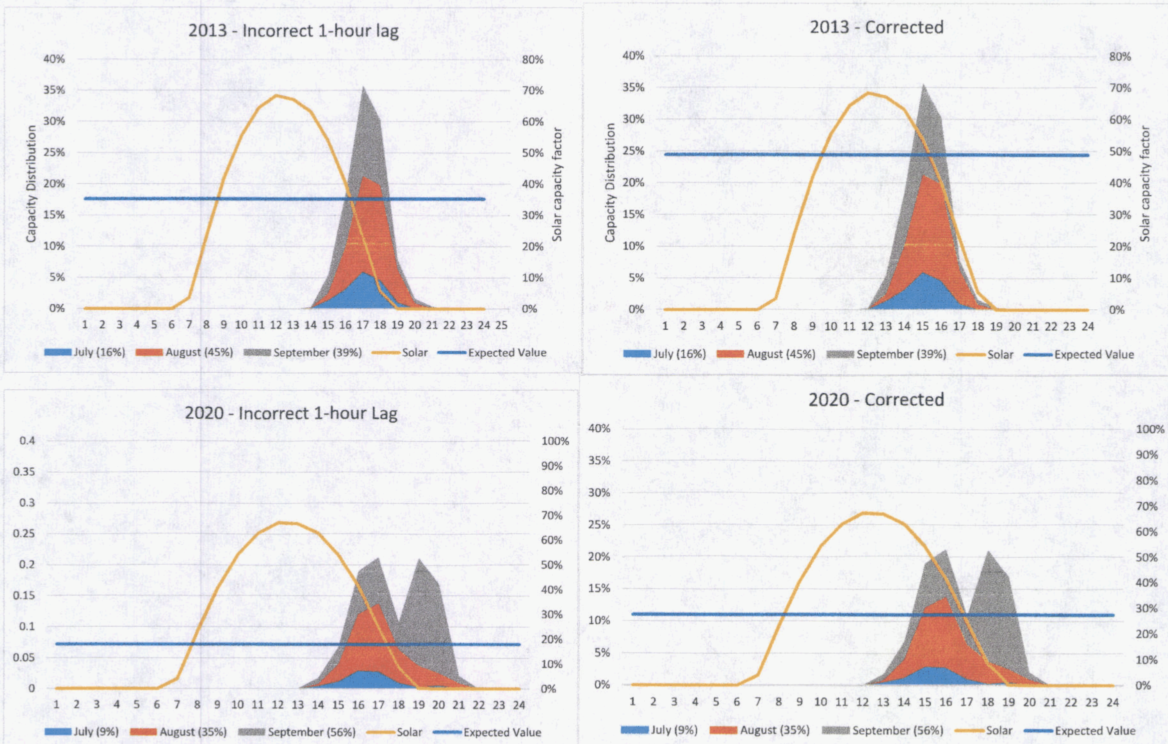

Figure A2: Revise Market Heat Rate to Reflect Post-SONGS Values