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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering.	Rulemaking 14-07-002 (Filed July 10, 2014)

COMMENTS OF THE ALLIANCE FOR SOLAR CHOICE, THE SOLAR ENERGY INDUSTRIES ASSOCIATION, AND THE CALIFORNIA SOLAR ENERGY INDUSTRIES ASSOCIATION ON THE DRAFT VERSION OF THE PUBLIC TOOL

CALIFORNIA SOLAR ENERGY INDUSTRIES ASSOCIATION
Brad Heavner
555 5th Street, #300-S
Santa Rosa, CA 95401
Telephone: (415) 328-2683
Email: brad@calseia.org

Policy Director for the California Solar Energy Industries Association

GOODIN, MACBRIDE, SQUERI & DAY, LLP
Jeanne B. Armstrong
505 Sansome Street, Suite 900
San Francisco, California 94111
Telephone: (415) 392-7900
Facsimile: (415) 398-4321
Email: jarmstrong@goodinmacbride.com

Attorney for Solar Energy Industries Association

KEYES, FOX & WIEDMAN LLP
Joseph Wiedman
Jacob Schlesinger
Samuel Harvey
436 14th Street, Suite 1305
Oakland, CA 94612
Telephone: (510) 314-8202
Email: jwiedman@kfwlaw.com

Attorneys for The Alliance For Solar Choice

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In accord with "Administrative Law Judge's Ruling Seeking Comment on Draft Version of Public Tool," issued April 15, 2015 (Ruling), the Alliance for Solar Choice, the Solar Energy Industries Association, and the California Solar Energy Industries Association, and (hereinafter, the Joint Solar Parties) respectfully submit the following comments.

I. INTRODUCTION

The Joint Solar Parties appreciate the opportunity to present the following comments on the draft Public Tool. Because there remain many questions about the Public Tool that are unanswered and important functionalities are lacking, we are skeptical that the Public Tool can serve as a fair analytic frame for analyzing the issues associated with the NEM 2.0 successor tariff. Significant methodological changes are needed, and parties need more information about how the Public Tool works and the sources of the many assumptions that are used in it. The draft Public Tool is a model that is complex, difficult-to-understand, and time-consuming to run.

The Joint Solar Parties hope that these comments will help the Energy Division and E3 to produce a final version of the Public Tool with accurate results based on transparent data, sources, and methodology. At this point, the Joint Solar Parties have not decided whether the Public Tool provides an adequately understandable and transparent basis for a fair analysis of a NEM 2.0 successor tariff.

II. RESPONSE TO QUESTIONS

Question 1. Input Descriptions and Documentation Materials

1. Revenue Requirement

The default data in "RR inputs" and "RR Calculations" tabs is lacking specific sources and citations. Rate forecasts are one of the biggest drivers of the cost-effectiveness test results, so it is important to understand how they are derived.

Some of the results of the Public Tool are unexpected and could be linked to revenue requirement increases in the General Rate Case filings relied upon in the Revenue Requirement Model. For example, capital expansion revenue requirements for both distribution and generation are simply the last attrition year in each rate case, escalated at an input rate. With respect to distribution revenue requirements, to the extent that the numbers relied upon were from the utility filings (rather than decisions), adjustments would need to be made to reflect the actual or likely outcome rather than the utilities' starting position, which has historically been much higher than approved amounts. Second, in recent years PG&E and SCE both have emphasized safety-related upgrades to their aging systems, which manifest as projected near-term, one-time increases to their distribution investment. Any escalation rates must take into account these – and any other – one-time investments reflected in a GRC. Third, the capital expansion revenue requirements for generation are also based on a simple escalation from the last attrition year, and therefore do not reflect the utility-owned generation investment embedded in the rest of the model. While the Joint Solar Parties acknowledge that users can change the escalation rates for these variables, compensating for the problem is not as accurate as fixing the problem. In addition, the "default" value is important for other parties who may not wish to delve into these issues to more accurately model their scenarios.

Question 2. Computational Errors

1. Impact of Renewable Energy Credit (REC) Treatment

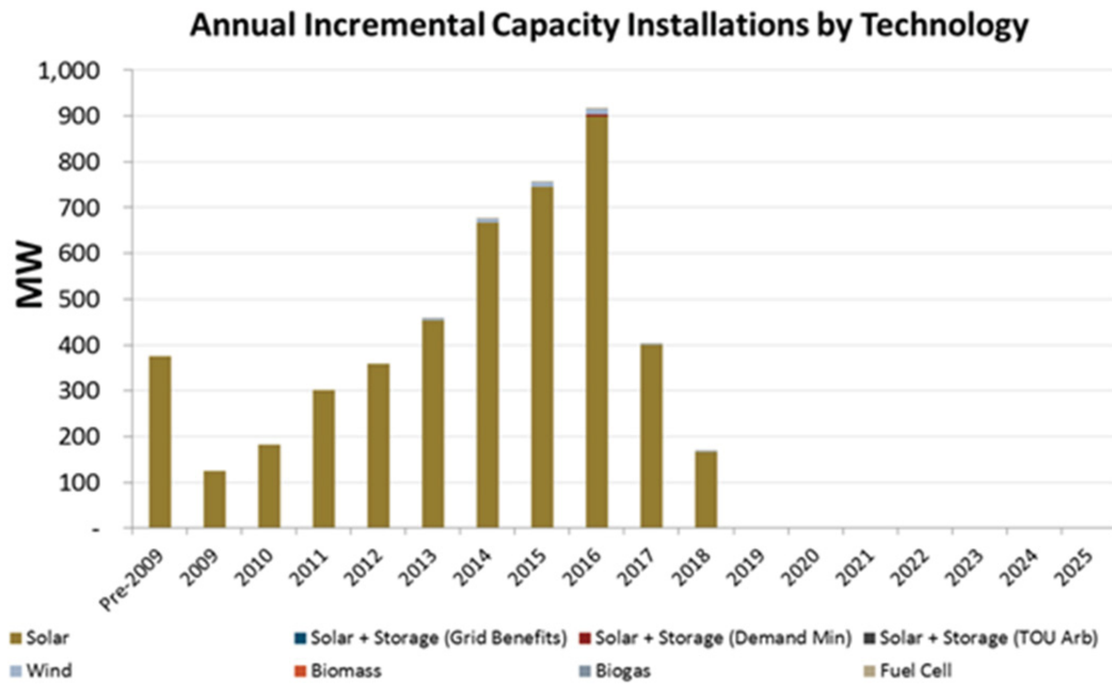
If customer behavior results in an avoided cost to a utility, then the utility should have a commensurate reduction in revenue requirements. This is not always the case in the Public Tool. For example, making Distributed Energy Resources (DER) count for Bucket 1 RECs (in the Key Driver Inputs tab at cell C8) increases avoided costs in the model results but does not significantly reduce revenue requirements. This is likely either a malfunction of the tool or an overly aggressive assumption about banked RPS RECs. It would be reasonable to place distributed generation (DG) RECs behind some amount of banked RPS RECs, but this type of effect should not be so strong as to nearly negate the impact of making RECs available to utilities from DG. To the extent that this overstates the revenue requirements, it has the impact of overestimating any cost shift.

Also, cell C8 on the "Key Driver Inputs" tab is the flag to choose whether all NEM generation or NEM exports count as Bucket 1 RECs for RPS compliance. The comment on this cell says, "*The option 'All NEM Successor DER Gen Counts for Bucket 1' is ONLY compatible with a 'Cost Based Compensation' or 'Value Based Compensation' structure as defined in the Basic Rate Inputs tab*." This is not consistent with how the model operates. When Bucket 1 REC treatment is selected for all NEM output, the avoided cost results change even if the NEM Successor Tariff compensation stays at the Full Retail Rate in the Basic Rate Inputs.

2. Basic Results in the Adoption Tool Are Clearly Wrong

A "business-as-usual" case for 2017 demonstrates that the adoption model is faulty. Such a case includes: (1) the federal Investment Tax Credit (ITC) stays at 30% in 2017 then drops to 10% in 2018; (2) NEM remains at the full retail rate credit; (3) the existing four-tier rate design is preserved; and (4) consumers expect future retail rates to rise at 3% per year, consistent with recent trends and forecasts. In this case, installations in the adoption model fell by 56% from 2016 to 2017, as shown in Figure 1.

Figure 1. Drop-off in Adoption Despite Continued Policy Support



In response to a question about this scenario, E3 stated (#1-16) that the problem is not in the adoption model, but in the trajectory of installations shown for 2015 and 2016. This explanation does not make sense because the business as usual installations in 2017 are well below the actual, historical level of adoptions in 2014. Installations should not drop significantly in 2017 compared to actual experience in 2014 if none of the key drivers of solar adoption has changed from 2014.

E3 also suggests, in response to a similar question (#1-17), that the drop in adoptions could be due to the most favorable customer "bins" reaching saturation, such that the rate of adoption would slow. This seems unlikely given that the number of solar customers in the state (250,000 based on the *California Solar Statistics* tally) is less than 3% of the more than 10 million investor-owned utility (IOU) customers, and the addressable market is 35% to 60% of the IOU customer base.

3. Storage Adoption

Setting the cost of storage equal to the storage incentive level should result in high adoption of storage. The SGIP incentive is $1620 per kW, so setting the price of storage at $1620 per kW makes the net cost of storage minimal for customers. The cases we ran with this low-cost storage included retail rates with significant TOU rate differentials and large demand charges that should support both TOU rate arbitrage and demand charge minimization. However, in these scenarios, the Public Tool continues to produce very small adoption levels. In addition, there was virtually no difference in the avoided costs for solar compared to solar plus storage; we would expect storage to increase avoided cost benefits significantly. The response to Question 45 states that low storage adoption must be due to "poor customer economics." This is implausible in a case where storage is virtually free, and the only significant cost of storage is the 15% round-trip losses. The case we ran with very low-cost storage included many retail rates with significant TOU rate differentials and large demand changes that should support both TOU rate arbitrage and demand charge minimization.

Question 3. Logical Inconsistencies

1. NEM True-Up

At the end of each annual billing period, NEM customers lose any remaining balance in unused NEM credits. This is known as the annual NEM True-Up. This loss of unused bill credits reduces lost revenues for the utility. The Public Tool does not appear to include this impact. This omission impairs the cost-effectiveness results and the cost of service results in the Public Tool.

2. System Sizing

The Public Tool assumes most future customers will install systems that offset 100% of onsite load. These results can be seen in cells AE148-AE150 of the Results tab. In a typical model run, around 67% of customer adoption is "Large systems" that serve 100% of customers' loads. This is unrealistic for several reasons:

1. Customers tend to be conservative. If the benefits are similar for different sized systems, then most will choose the smaller system.
2. Many customers are limited by available roof space. Some people who are counted as potential customers in the technical potential of solar do not have enough roof space to size their systems to offset all of their load.
3. Solar customers on TOU rates should not size their system to offset 100% of onsite load.
4. Minimum bills can reduce or eliminate the benefits of sizing a system beyond a certain percentage of annual consumption.

To address this problem, the adoption model should include the following assumptions:

- If the net present value of systems of different sizes are effectively equal, then customers will adopt the smaller size.
- The number of customers opting for "Large systems" should be scaled back due to limited roof space.
- No commercial or agricultural customers should be allowed to adopt "Large systems" because they will be on TOU rates.
- Large systems should be capped at the percentage of customers that are not on TOU rates. Currently, that would suggest that no more than 53% of residential solar customers should be allowed to adopt "Large systems.[1]

3. Curtailment

The Public Tool calculates significant future curtailments of renewable generation, particularly in the 50% RPS case. This reduces the cost-effectiveness of DER, and may increase integration costs. The model appears to assume that the curtailed generation is not produced, but is paid for by consumers.

It is not reasonable to assume that load shifting and energy balancing will fail and that large amounts of curtailment will occur. The following efforts are underway to prevent curtailment:

- In 2014, CAISO led the implementation of a regional market to assist in the integration of renewables across the entire WECC footprint. The new Energy Imbalance Market that is the product of this effort has a central goal of reducing renewable curtailments.
- Nearly all commercial and agricultural customers are now or will soon be on time of use rate schedules, and the proposed decision in R.12-06-013 orders the utilities to propose default time of use tariffs for residential customers starting in 2018. Customers will change their usage patterns in response to time of use rates.
- Many demand response options are under consideration in R.13-09-011.

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1 PG&E total NEM customers of 79,901 through December 2013 based on CSI database for customers interconnecting before 2011 and PGE response to CALSEIA data request for 2011-2013. PG&E NEM customers on E-6 and E-7 of 37,844 per PG&E/Nexant, "2013 Load Impact Evaluation of Pacific Gas and Electric Company's Residential Time-based Pricing Programs," April 1, 2014 at 16 (subtracting non-NEM from total).

- The deployment of storage resources provides a means by which customers can respond to time of use rates and demand response signals. Storage serves as a sink that can absorb solar energy at times when resources would otherwise be curtailed.
- The Commission adopted procurement requirements for flexible resource adequacy capacity, which ensures sufficient generation capacity is available for dispatch in the CAISO market. Although the primary initial focus has been on sufficient upward ramping capacity, the product definitions and corresponding must-offer obligations are designed to provide both upward and downward ramping capacity, which will significantly reduce the likelihood of curtailment in the 50% RPS scenario, since a significant portion of supply in CAISO's market today is "self-scheduled" into the market as price takers, despite possessing the operational capability to generate flexibly.
- Implementation of FERC Order 764 in 2014, requiring renewable resources to provide 15-minute forecasts at the CAISO interties, will reduce forecast error and associated cost of curtailment due to suboptimal dispatch of inflexible conventional resources.
- Lowering CAISO's price floor to -$150/MWh creates a significant price signal for inflexible conventional resources to invest in operational flexibility. Increased ability by conventional resources to ramp generation down in the middle of the day will reduce the need for curtailment.

These measures can eliminate the need for curtailment. The Joint Solar Parties recommend that the final Public Tool include the ability to change the level of curtailment and assume that curtailed RPS generation can be sold in a regional market at a market price.

5. SPM Base Case

The Standard Practice Manual cost-effectiveness tests require a comparison between the policy case and a base case. In the Public Tool, the base case for the cost-effectiveness tests is zero adoption of solar. It is incorrect to assume that without net metering there would be no adoption of solar. In effect, the model is comparing lots of solar with no solar, when it should be comparing less solar without a successor tariff versus more solar with a successor tariff.

This error amplifies any negative results in the cost-effectiveness tests and cost of service analysis. The Public Tool should include a base case that has some level of solar adoption from customers that size on-site generation to offset on-site demand without exporting power.

6. Power Charge Indifference Adjustment

The Public Tool incorrectly combines the Power Charge Indifference Adjustment (PCIA) with non-bypassable charges (NBCs). In so doing, the Public Tool applies the PCIA to all customers rather than only applying it to direct access (DA) and community choice aggregation (CCA) customers.

Also, the Revenue Requirement model calculates the PCIA revenue requirement incorrectly. The PCIA in the model is the difference between the RPS costs and the "market value" of the RPS energy. While this gets at the concept that the PCIA is associated with IOU "stranded costs" (i.e., costs above the market), it does so in an incomplete manner by only considering above-market RPS costs. The actual PCIA is based on the "Total Portfolio Cost," whereby generation contracts and assets that are above market cost are netted against those below market cost. Furthermore, the actual PCIA is allocated in rates using the top 50 hour method (the same as the CTC), rather than the equal cents per kilowatt-hour allocation that it receives when lumped in to the NBC category.

The overall impact of these errors is inflation of NBCs, which skews the cost-effectiveness tests. Rigorously calculating the PCIA, including the appropriate vintages, would be an exercise in false precision. For the task at hand, it would likely be acceptable to use the historical average PCIA rate times the DA/CCA load, and simply deduct this amount from the bundled generation revenue requirement.

Question 4. Assumptions to Move to Key Driver Inputs Tab

1. Rate Escalation

As explained in Response 2 to Question 6 below, the rate escalation for SCE and SDG&E is excessive. Parties should have the ability to adjust this percentage escalation for each IOU in the key driver inputs.

2. Structure of the Cost of Service Analysis

A utility does not have a right to the portion of generation that is consumed on-site and never passes to the utility side of the meter. This consumption of self-generated power should not be included in the cost-of-service analysis. A utility incurs costs to serve a customer only when the meter rolls forward; customers do not pay when they reduce their use of electricity from the grid by other means, such as turning off the lights when they leave the house.

a. Gross vs. Net Load

With respect to the cost of service analysis, one key issue is whether or not solar customers cause certain cost categories to be incurred based on their gross load or their net load. Accordingly, the Public Tool should include a toggle to treat the cost-of-service for these distribution cost components based on net load, in the same way that the cost of service was modeled under the "low case" in the Commission's 2013 "California Net Energy Metering Ratepayer Impacts Evaluation" (2013 Model). Without such an option, the Joint Solar Parties do not believe that the Public Tool provides an accurate, equitable, or useful means to evaluate cost of service issues.

Table 1. Cost of Service Table from 2013 E3 Report

Table 44: Full Cost of Service Scenario use of Net or Gross Loads

Marginal Cost Category	No NEM DG Case	Low Case	Utility Case	High Case
Generation Energy	Gross	Net	Net	Net
Generation Capacity	Gross	Net	Net	Net
Transmission (SCE)	Gross	Net	Net	Gross
Transmission (PG&E and SDG&E)	Gross Bill Pass-Through	Net Bill Pass-Through	Net Bill Pass-Through	Net Bill Pass-Through
Subtransmission (SCE)	Gross	Net	Gross	Gross
Distribution (SCE and SDG&E)	Gross	Net	Gross	Gross
Primary Distribution (PG&E)	Gross	Net	Gross	Gross
Primary New Business (PG&E)	Gross	Net	Gross	Gross
Secondary Distribution (PG&E)	Gross	Gross	Gross	Gross
Customer Cost	Gross	N/A	N/A	N/A

Net load is the account's hourly usage after it has been reduced by the DG output. Gross load is the account's hourly usage absent the DG. Net Load = Gross Load - DG Output.

b. CARE

Another key issue is the treatment of CARE costs in the cost of service model. In the workshop slides, E3 highlights the fact that this is a departure from the 2013 study. While we appreciate E3's acknowledgement in the Q&As that CARE costs should not have been allocated exclusively to residential customers in the cost of service study, we recommend that the final version of the Public Tool include an option to treat the CARE costs in the same way they were treated in the 2013 study, so that users of the model can isolate this departure in methodology and more easily compare results to the previous study.

c. System Sizing

Finally, the Joint Solar Parties would like to highlight the interplay between the cost-of-service results and the system sizing concerns raised above. To the extent that system sizing is unrealistically biased toward 100% energy offset, the model will produce results that show a smaller percentage of cost of service being paid by each technology. This is a major shortcoming of the modeling framework, and needs to be fixed if the cost of service results are to be used as a basis for decision making.

3. Coordination with Distribution Resource Plans

Consistent with avoided cost calculations, customers should not be allocated service costs that are actually avoided by their systems and behavior. To the extent IOUs are avoiding categories of costs due to enhanced distribution planning, failing to include those same categories of costs in the Public Tool would result in inaccurate results.

Addressing this breakdown in coordination is the objective of the IOUs' enhanced distribution plans, which are being updated as part of AB 327 and the Commission proceeding on Distribution Resource Plans, R.14-08-013. By July 1, the IOUs will propose new distribution resource plans that enable modernization of the electric distribution system, enable customer choice of new technologies and services, and promote opportunities for distributed energy resources, including customer-sited DG, to provide grid services and realize the attendant benefits of doing so. Among other new categories, the utilities will quantify a more comprehensive set of avoided costs for the distribution system going forward, identified in the table below. However, despite the adoption of these new categories of avoided cost by the IOUs, the Public Tool does not currently recognize them as new categories.

Table 2. Value Categories in DRP Guidance[2]

Category	Definition of cost	Status
Distribution Capacity	Capital and operational costs incurred for local distribution capacity upgrades	Existing
Distribution Power Quality	Capital and operational costs incurred to maintain transient and steady-state voltage, harmonics and reactive power	New in 2015
Distribution Reliability	Capital and operational costs incurred to reduce frequency and duration of outages	New in 2015
Distribution Resiliency	Capital and operational costs incurred to increase ability to withstand and recover from external threats	New in 2015

The Joint Solar Parties recognize that the sequencing of the Distribution Resource Plans and NEM 2.0 proceeding presents a challenge. However, as previously stated, it would be inconsistent if the Public Tool in this proceeding fails to allow parties to anticipate the wider scope of avoided costs than historically considered for energy efficiency. The utilities are required by the Commission to consider these enhanced criteria, including capital investments and operating expenditures related to maintaining capacity, power quality, reliability and resiliency, in determining optimal locations for DER deployment and supporting incentives. The Commission should allow parties to input user-defined values in the Public Tool for power quality, resiliency and reliability.

4. Market Disruption

The Joint Solar Parties are concerned that the adoption model, by only considering the pure economics of successor tariff proposals that may be proposed by stakeholders, will tend to overstate adoption in circumstances where the successor tariff varies considerably from the current NEM tariff. If the successor tariff is vastly different from NEM as currently designed and implemented, then there will be some level of disruption relative to circumstances where the successor tariff looks substantively similar to the current NEM tariff. To that end, the Public

2 CPUC, "Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resources Planning," issued February 6, 2015 in R.14-08-013.

Tool should include a disruption factor as a user input that dampens adoption during a transition period.

Question 5. Societal Inputs

1. Job Growth

As documented by the Solar Foundation, 54,000 Californians now work in the solar industry, and that number is expected to grow 17% this year.[3] A successor tariff that dampens adoption will have a negative impact on employment. A successor tariff that enables the market to continue growing will have a positive impact on employment. Parties should be able to include both of these impacts as use inputs in the Public Tool.

2. Local Pollution

The Commission should include the avoided environmental health costs associated with reductions in local pollutants. The health care burden associated with fossil fuel generation has been well documented, including by U.S. EPA. In particular, outdoor air pollution can increase the severity of asthma attacks and other respiratory illnesses in vulnerable populations living in close proximity to fossil fuel-fired plants.[4] NEM and customer-sited DG result in reduced fossil fuel generation in California, especially from less efficient peaker plants that result in more air pollution per kWh produced during times of peak demand. Avoiding the use of less efficient natural gas peaker plant generation, in turn, reduces air pollutants associated with those plants. Considering the fact that peaker plants are often located in disadvantaged communities, NEM and customer-sited DG lower the health care burden from electricity generation on these populations and avoid emissions of air pollutants that are known to increase the frequency and severity of asthma attacks and the risk of developing other respiratory illnesses in vulnerable populations.

Question 6. Erroneous or Outdated Data Inputs

1. Locational Prices

The Public Tool does not incorporate locational marginal prices. Energy prices vary throughout the state, and an initial investigation reveals that energy prices are higher, on average,

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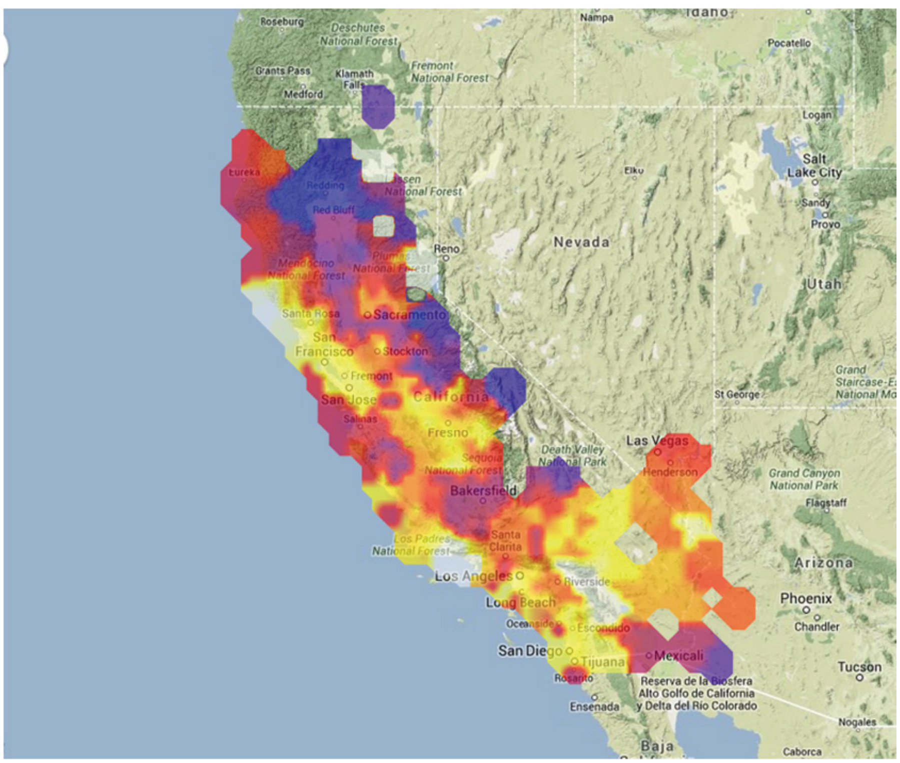
3 The Solar Foundation, "California Solar Jobs Census 2014," February 2015.

4 *See* X. Liu, L. Lessner and D. Carpenter, *Association between Residential Proximity to Fuel-Fired Power Plants and Hospitalization Rate for Respiratory Diseases*, Environ. Health Perspect. v. 120:807-810, June 2012.

in places where solar installation rates are higher. The Public Tool uses a statewide average energy cost that is not weighted based on the geographic concentration of DER. The Tool therefore undervalues solar because solar historically has offset utility costs in places where costs are high, and this trend should be expected to continue. Locations where the grid is congested are places with a high density of utility customers and therefore a high concentration of DER. Figure 2 is a "heat map" that shows where utility avoided costs from local solar generation are higher. Using 2011 Locational Marginal Prices from CAISO and capacity prices reported by the Commission, the map quantifies the value of energy and capacity associated with latitude-adjusted hourly photovoltaic production estimates that include insolation and cloud cover. White is highest and blue is lowest. Based on the CSI database, the 50 highest value Locational Marginal Price nodes have more than 10 times the capacity of installed solar as the 50 lowest value Locational Marginal Price nodes.

Figure 2. Magnitude of Utility Avoided Costs from Solar[5]



This effect may increase under the Distribution Resources Plans that the utilities are developing in R.14-08-013. To the extent that tariffs increase the financial incentive to install DER in locations where the grid is congested, solar will increasingly offset higher than average

5 Kevala Analytics, "Avoided Cost Solar Heatmap," www.kevalaanalytics.com/projects.

generation and capacity costs. The final Public Tool should allow avoided energy and capacity costs to be adjusted upward to recognize such locational benefits.

In addition, with recent and anticipated retirements of large coastal conventional generating units, there are large local regions where the avoided generation capacity value should reflect the cost of a new unit – effectively having a near-term resource-balance year (RBY). However, in the Public Tool, the avoided generation capacity is only based on the *system* RBY. While the Public Tool allows the user to move the RBY forward, it can only do this for all system resources. Consequently, there is little overall benefit because it causes the avoided RPS value to go down. The Public Tool should allow for the DG resource to avoid higher cost local capacity while the avoided RPS resource avoids lower cost system capacity.

2. Rate Escalation

The future escalation in SCE's and SDG&E's retail rates is much higher than the growth in PG&E's rates. This is evident in Slide 28 from the E3 presentation at the March 30 workshop. SCE and SDG&E average residential rates double by 2035 and even in 2025-2030 are 30% to 50% higher than PG&E's rates. This trend is independent of the amount of DER installed.

The Public Tool's stated assumption for escalation in distribution and generation O&M is with inflation, two percent (2%), but the actual annual growth rates for distribution and generation O&M, in the Revenue Requirements model, are 5% to 7% per year for a sustained number of years. These high and sustained escalation rates can be seen at the following lines of the RR Calculations tab – 147, 418, 534, 705, and 820. This rapid growth in O&M expenses is not reasonable. The response to Question 28a asserts that "O&M is a function of inflation and plant in service," and that if plant in service doubles, then O&M should double. The Joint Solar Parties fundamentally disagree with this assertion. Much of the distribution capex is for the replacement of existing facilities, which, if anything, should reduce O&M by replacing older facilities with more modern equipment. In fact, the Revenue Requirement model (RR Inputs tab, lines 342-344) has defaults that assume that only 11% of the distribution capex is due to new plants. New distribution facilities serving new loads also can have lower O&M costs, for example, if the new distribution circuits are underground instead of overhead. Finally, capex such as better metering and instrumentation can reduce O&M by allowing more efficient use of O&M resources. The response to Question 28a is phrased as though all capex are discrete generating units that all have similar unit O&M costs. This is simply not the case – the utilities are adding relatively few utility-owned power plants, and are purchasing most incremental generation.

For SCE and PG&E, the generation capital expansion amounts appear to be the last year of a GRC approval, escalated by a prescribed amount. For SDG&E, the generation capital expenditure is based upon the distribution capital expenditure and the historic ratio between generation and distribution rate base. These assumptions are not reasonable. The IOUs are not likely to invest in new generation assets at the same rate as they have in the past. Most recent growth in utility generation portfolios has been met through PPAs.

In the Public Tool, future rate increases escalate without limit. This is not realistic. At some point public outcry and business pressures will force the utilities to trim their spending. Also, utilities will face competition from microgrids, which will create an upper limit on rates.

3. Investment Tax Credit

The ITC has a major impact on solar adoption. In the Public Tool, all residential systems are assumed to get an ITC of 10%. The ITC is scheduled to be reduced to 10% for commercially-owned systems, and is scheduled to be eliminated entirely for residentially-owned systems. The Tool should correct this error and allow different values for commercial and residential systems.

4. Line Losses

A marginal cost or avoided cost analysis of the benefits of DER should use marginal line losses. The Public Tool appears to use average losses, which are typically roughly half the rate of marginal line losses. Because increased DER will reduce line losses at the margin, the Joint Solar Parties propose that the Public Tool use marginal line losses instead of average line losses. At a minimum, the Tool should allow the use of marginal line losses as an alternate input.

5. Distribution Marginal Costs

For PG&E, distribution marginal costs are specified by customer baseline territory. In the 2013 Model and in GRCs, PG&E presents marginal distribution costs by division. There is likely to be a significant reduction in accuracy in converting marginal distribution cost inputs from divisions to baseline territories.

If there is a large increase in distribution costs in a particular area that can be mitigated with DER, the bill savings will be out of line with the cost savings if there is a loss of geographic granularity. In the future, the Distribution Resources Planning process will encourage energy storage and other DER to be located in high value locations. Those benefits are lost in the model if it averages costs over a larger area.

Question 7. Any Other Changes

1. DA/CCA

In the Revenue Allocation tab, the Public Tool assumes the current levels of DA and CCA customers. Given the movement to expand DA and the interest throughout the state in CCAs, this understates the amount of DA and CCA loads that can be reasonably expected.

Although the revenue requirement model tracks the amount of DA/CCA load to correctly allocate the T&D costs, the Public Tool considers only bundled customers. Currently, significant fractions of the large commercial and industrial classes are on DA service, and there is great interest in additional CCAs. Because DA and CCA rates are relatively close to the IOU generation rates (i.e. +/- a few percent), including the DA/CCA load in the adoption models could be a reasonable shortcut. However, because a potentially large fraction of the DER adopters would not be offsetting utility generation rates, excluding DA/CCA loads results in significant inaccuracy when performing the utility and ratepayer impact (RIM) cost-benefit test and the cost of service comparisons.

III. CONCLUSION

The Joint Solar Parties appreciate the opportunity to file these comments.

Respectfully submitted this April 28, 2015 in San Francisco, California.[6]

GOODIN, MACBRIDE
SQUERI & DAYLLP
Jeanne B. Armstrong
505 Sansome Street, Suite 900
San Francisco, California 94111
Telephone: (415) 392-7900
Facsimile: (415) 398-4321
E-Mail: jarmstrong@goodinmacbride.com

By /s/ *Jeanne B. Armstrong*
Jeanne B. Armstrong

Attorneys for the Solar Energy Industries Association

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6 In accordance with CPUC Rule 1.8(d), counsel for SEIA is authorized to sign these comments on behalf of the Joint Solar Parties.