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)

POST-WORKSHOP COMMENTS OF THE VOTE SOLAR INITIATIVE

Susannah Churchill
Regional Director, West Coast
The Vote Solar Initiative
101 Montgomery Street, Suite 2600
San Francisco, CA 94104
Tel: (415) 817-5065
Email: susannah@votesolar.org

Dated: October 1, 2014

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POST-WORKSHOP COMMENTS OF THE VOTE SOLAR INITIATIVE

In accord with the September 5, 2014 Administrative Law Judge's Ruling in the above captioned proceeding, The Vote Solar Initiative (Vote Solar) submits these post-workshop comments regarding various aspects of the Public Tool, which will assess the costs and benefits of options for a successor to the existing net energy metering tariffs. Given the technical nature of a number of the questions in the Ruling, we do not offer answers to every question at this time, but list those for which we do have a response below. We reserve the right to comment on other parties' responses on all the questions in reply comments.

1. ***Are there any comments or concerns regarding the proposed approach of developing a public tool in conjunction with a report containing the range of results from the tool? If so, what alternative approaches should be considered?***

Presumably, this question does not mean that a report containing the range of results would be finalized at the same time as the Public Tool itself, i.e. around the end of 2014, but rather that a report would be finalized later in 2015 summarizing the results of various parties' modeling using the Public Tool. We consider the latter to be a reasonable approach, with the caveat that the executive summary and summary tables of the report must be comprehensive in summarizing all well-supported results from the various parties, as opposed to choosing just a few scenarios, such as the investor-owned utility (IOU)-developed results, to include in summary tables. The different assumptions and inputs used across the various scenarios will have major impacts on the net benefits or costs estimated. By summarizing the full range of well-supported results, the Commission will allow stakeholders and policymakers who review only the report summary to be properly informed about the full range of cost-benefit impacts that result from different data inputs and methodological assumptions.

2. ***Are there any lessons learned from prior public tools (e.g. utilities' rate design tools), or examples of public tools that have been done well, that could inform the development of the proposed Public Tool? For reference, the Nevada Net Metering Public Tool (http://puc.nv.gov/About/Media_Outreach/Announcements/Announcements/7/2014_-_Net_Metering_Study/) was mentioned during the public workshop held on August 11, 2014 as an example of a public tool that was done well. Please be specific in your recommendations for what did and did not work well.***

E3's Nevada Net Metering Public Tool noted in the question is a good starting point for the development of California Public Tool. One positive characteristic of the Nevada Public Tool its ease of use: the model can be easily run by those with only a basic knowledge of Excel, allows the user to change a few key inputs, and reports results in easy-to-read bar graphs of levelized cost/benefit and Net Present Value, as well as results summary tables that change. Second, the Nevada Public Tool includes all five key ratepayer perspectives — using the participant, non-participant, utility, total resource cost, and societal cost tests - and produces separate but easily comparable results for each perspective. However, certain methodological flaws in the Nevada Net Metering Public Tool should not be repeated in California. These flaws include:

- The Nevada Public Tool did not include a cost of service analysis. A cost of service analysis is key for assessing whether net metered customers are paying more or less than what it costs the utility to serve them under a given tariff, as discussed in the response to Question 19 below.

- The Nevada Public Tool inappropriately included SolarGenerations incentives as a cost of net metering. A state's solar incentive program is entirely separate from net metering, with a finite budget approved by the Legislature, and should not be part of a net metering study. If the impact of incentives had not been included, net metering in Nevada would have been shown to deliver further net benefits to ratepayers.
- The Nevada Public Tool did not include an exports-only scenario. Just like turning off the lights or buying a new refrigerator to reduce energy use, solar that is both produced and used behind the customer's meter places no burden on the utility system, and should not be part of the cost-benefit equation. The 2013 California E3 NEM study assessed an exports-only scenario separate from an all-output scenario, and we strongly encourage the California Public Tool to do the same.
- The Nevada Public Tool modeled zero distribution benefits in the base case scenario, which produces the default results seen by users who do not change any user inputs, but did not make this very conservative assumption clear in the model itself. E3 noted in the accompanying report to the Nevada Public Utilities Commission that distribution benefits are "not included in the base case because NV Energy distribution engineers do not consider the intermittent output of NEM systems reliable enough to avoid the need for distribution system upgrades. In reality, some portion of distributed generation could probably reliably defer some distribution upgrades."[1] Given that the value of a number of types of net metering benefits (and costs) will continue to be controversial, the

[1] "Nevada Net Energy Metering Impacts Evaluation," E3, July 2014, page 14.

California Public Tool should not include base case scenarios that assume a zero value for those categories of benefits or costs, but rather should seek to use a reasonable midpoint for various types of contested costs and benefits in any base case scenarios.

- The Nevada Public Tool omits almost all the societal benefits of net metering. No study on the impacts of clean distributed generation is complete without taking into account benefits such as job creation and downstream economic effects, water savings, and public health improvements. Yet, the Nevada Public Tool includes just one societal benefit — public health cost savings associated with air emissions, and even there, the study used NV Energy's relatively low cost of avoiding such emissions, which is an inaccurate proxy for the value of avoided premature deaths and healthcare cost savings.[2] One way to avoid this problem in California would be to ensure that unlike the Nevada Public Tool, the California Public Tool includes a user-modifiable input or series of inputs for "other benefits," allowing stakeholders to include supportable values for societal benefits associated with renewable distributed generation that have not been accounted for in other portions of the model.

4. ***Using the E3 avoided cost calculator, the proposed avoided cost components to measure the benefits of renewable distributed generation are listed below. Note that items a-g were included as part of the 2013 NEM Ratepayer Impacts Evaluation (2013 NEM Report).***
    a. ***Energy purchases***
    b. ***Generation capacity***
    c. ***Transmission and distribution capacity***
    d. ***Greenhouse gas emissions***
    e. ***Losses***
    f. ***Ancillary services procurement reduction***
    g. ***Reduced Renewables Portfolio Standard (RPS) procurement***
    h. ***Additional value (included as a user defined input in the total resource cost / societal test)***

[2] As noted in "Nevada Net Energy Metering Impacts Evaluation," E3, July 2014, pages 63-64.

Are there any avoided cost components that should be added to or removed from this list? Please give specific reasons for each proposed addition or deletion.

In addition to the above list, the following three avoided cost components should be included in the Public Tool, all of which are described in a September 2013 meta-analysis by Rocky Mountain Institute's Electricity Innovation Lab entitled "A Review of Solar PV Benefit & Cost Studies."[3] That report details other studies in which each of these additional benefits have been quantified:

1) **Market price mitigation:** Customer-sited renewable DG provides electricity close to demand, thereby reducing the demand for centrally-supplied electricity and the fuel powering those generators and thus lowering electricity prices and potentially fuel commodity prices.

2) **Fuel price hedge benefits:** Over and above market price mitigation, these are savings on costs that a utility would otherwise incur to guarantee that a portion of electricity supply costs are fixed.

3) **Energy security:** Three primary factors apply here:

    - The potential to reduce outages by reducing congestion along the T&D network. Power outages and rolling blackouts are more likely when demand is high and the T&D system is stressed.

    - The ability to reduce large-scale outages by increasing the diversity of the electricity system's generation portfolio with smaller generators that are geographically dispersed.

[3] See http://www.rmi.org/Knowledge-Center%2FLibrary%2F2013-13_eLabDERCostValue.

- The benefit to customers to provide back-up power sources available during outages through the combination of PV, control technologies, inverters and storage.

5. ***Are there any avoided cost components from the 2013 NEM Report that should be updated or modified? For example, during the August 11, 2014 public workshop, some parties identified the need to model a higher goal under the RPS, and/or a higher cost of greenhouse gas emission reductions. Please give specific reasons for each proposed change.***

We recommend the following additional elements should be modeled:

1) **Higher avoided renewables procurement costs and carbon costs:** With the enactment of AB 327, the Commission is authorized to require utilities to procure renewables in excess of existing RPS targets. In addition, Governor Brown stated at a United Nations meeting in New York last week, "in the next six months, [California is] going to set a [GHG] goal for 2030 that will be more ambitious, that will require more technology…" indicating strong political momentum for additional concrete GHG emissions reductions goals after 2020.[4] In order to achieve the state's longer-term goal of 80% reductions in greenhouse gas emissions from 1990 levels by 2050, recent studies[5] show substantial increases in

[4] See http://www.imperialvalleynews.com/index.php/news/california-news/11246-governor-brown-addresses-global-leaders-at-united-nations-climate-summit.html

[5] According to a November 2013 study by the Lawrence Berkeley National Laboratory (LBNL), California is on track to meet its 2020 climate goals, but is far from having the policies in place to meet its 2050 goal of 80% reductions in greenhouse gas emissions from 1990 levels. Scenario 3 of LBNL's analysis found that that even if California follows through on some of its most ambitious policy ideas including the following: 1) zero net energy building mandates for commercial and residential construction by 2020 and 2030, respectively, 2) 12 GW of distributed solar power by 2020, 3) a 51% renewables portfolio standard by 2030, 4) 3.3 GW of storage and 3 million zero emission vehicles, and 5) an average 77.9 miles per gallon fuel efficiency for light duty vehicles in 2050, the state will be only approximately two thirds of the way to its GHG emission reduction goal in 2050. "Estimating Policy-Driven Greenhouse Gas Emissions Trajectories in California: The California Greenhouse Gas Inventory

customer-sited and other renewable generation are likely to be needed in excess of current goals, in addition to electrification of the majority of the transportation sector. Thus, while the precise policy pathway is as yet unclear, the Public Tool should model renewables deployment levels significantly in excess of 33% starting in 2025 and increasing in years afterwards. In addition, the Public Tool should model higher carbon costs that will accompany more stringent post-2020 GHG standards.

2) **Increased loads due to electric vehicle (EV) deployment:** As noted above, analysis shows that electrification of the transportation sector will be key to achieving the state's longer-term GHG goals. Governor Brown recently signed SB 1275, legislation intended to put one million electric vehicles on the road by 2023.[6] The Commission should ensure that the load forecasts used in the Public Tool are properly accounting for significant increases in EV deployment between now and 2050.

3) **Significant penetration of customer-side PV-paired storage:** Storage paired with customer-sited solar photovoltaics (PV) is another technology with significant growth potential during the timeframe of the Public Tool's cost-benefit analysis. Companies including SolarCity are already offering solar-plus-storage options for residential and commercial customers, and the CPUC's storage standard for the IOUs requires that a portion of the standard be met with

Spreadsheet (GHGIS) Model," LBNL October 2013, http://eetd.lbl.gov/publications/estimating-policy-driven-greenhouse-g.

[6] See http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140SB1275&search_keywords=

customer-side storage. An increase in customer-side PV-paired storage could facilitate peak shaving, frequency regulation, and voltage support that could add up to significant grid benefits.

4) **Fixes to Avoided Cost Errors Noted in E3 2013 Study**: In our October 10, 2013 comments to the Energy Division, Vote Solar noted errors in the avoided costs used in E3's 2013 NEM Study, which were not fixed when that study was finalized. These include:

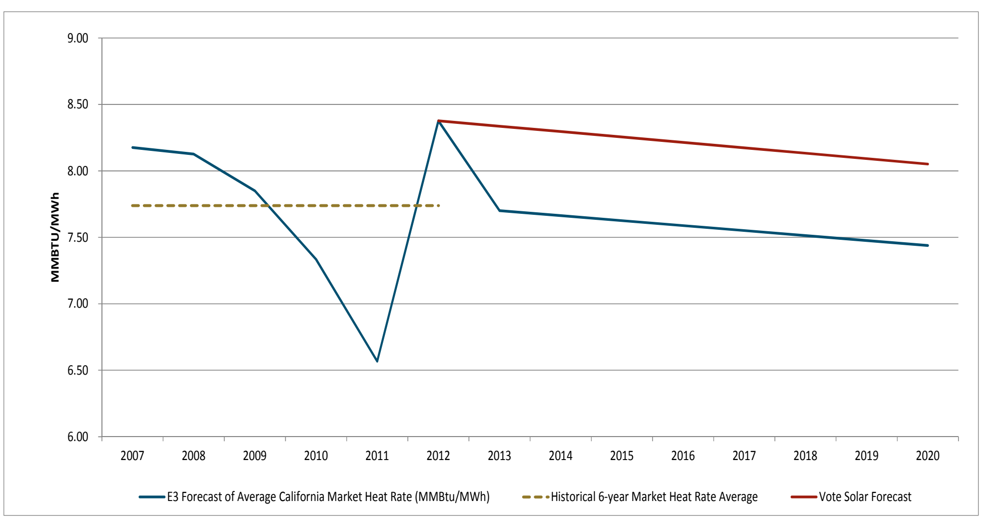
    a) **Include SCE and SDG&E's High-Voltage Transmission Costs:** The E3 avoided cost model fails to include avoided CAISO-jurisdictional high-voltage transmission costs for Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E), even though these IOUs have calculated these marginal costs, and E3 included all other IOU marginal T&D costs for sub-transmission and distribution. Pacific Gas & Electric's (PG&E) marginal transmission costs, however, did include CAISO-level costs. E3's response in the December 2012 Final Scope of Work 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 a 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." Since 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), these avoided costs should be included for all 3 IOUs in the Public Tool.

b) **Use Updated GRC Marginal Costs:** E3 stated in the Final Scope of Work that its 2013 study would use "the most recently available marginal cost estimates." E3 was responding here 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 the relevant costs to SCE's and SDG&E's most recently-filed marginal T&D costs.

c) **Market Heat Rates Should Use Post-SONGS Values:** The E3 2013 study noted (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 San Onofre Nuclear Generating Station (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.

E3 stated 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 1 below illustrates the numbers, with the red line indicating Vote Solar's proposed revision to the market heat rates.

Figure 1: Revise Market Heat Rate to Reflect Post-SONGS Values



6. ***Are there any other modifications to how the avoided costs should be determined? Please be specific. Include supporting materials if available and quantitative examples or illustrations when relevant.***

In R.12-11-005, parties developed a record on expected PV system life in the context of the determination of the transition period for customers who net meter under the current 5% program cap. The weight of evidence in the record in that proceeding supports 25 years, not 20 years, as a reasonable minimum estimate of the expected life of a PV system. As detailed in comments from Vote Solar and other solar parties in that proceeding, the leading manufacturers of solar modules installed in California offer warranties that guarantee power production will *exceed 80 percent* of their solar modules' power output rating for 25 years, and a 25-year power output warranty is a market standard among leading PV manufacturers. In addition, parties including the Net Energy Metering Public Agency Coalition noted that a website jointly managed by the Commission and the California Energy Commission, GoSolarCalifornia.ca.gov, links to solar payback calculators that assume a 25- to 30-year system life.

E3's Nevada Net Metering Public Tool, noted in Question 2 above, assumes a net metered PV system lifetime of 25 years; this assumption is hardwired into the Nevada model and cannot be modified as a user input. The avoided costs used in the California Public Tool should likewise levelize costs and benefits over at least a 25-year expected PV system life, and should not report results based on a single-year or few-year "snapshot" of costs and benefits.

The E3 2013 Study's de-emphasis of lifecycle results was 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 single earlier-year "snapshot" does not fully capture solar's value as a hedge against future increases in fossil fuel prices and the costs to mitigate GHG emissions in the later years of its lifecycle. The 2013 Study's Executive Summary did not present results for the lifecycle analysis, even though the Executive Summary of the 2010 E3 NEM report did. We strongly encourage the Commission to avoid this issue with the Public Tool by reporting all results levelized over at least a 25-year expected PV system life.

8. ***How should the utility costs should be determined? Should utility costs be determined separately for each investor-owned utility (IOU)? Why or why not? Please be as specific as possible. Include supporting materials where available.***

Vote Solar supports estimating costs and benefits separately by IOU, which will allow for more transparency and granularity in the results. We support using a standard methodology across IOUs, but note that certain inputs may differ across IOUs. For example, the average generation profile of solar in SCE territory is likely to differ from the average solar generation profile in PG&E territory, and the avoided costs associated with the gas-fired generation fleet will differ by utility. If a separate analysis is performed for each IOU, the Public Tool should also include a tab where results are aggregated across all three IOUs for a given possible tariff structure, so that statewide impacts of that tariff structure can be assessed.

10. ***The Public Tool will use data from a variety of sources for the purposes of the analysis. The proposed guiding principle for sourcing data is to use the best publicly available data, though there is some information that is not publicly available that will need to be gathered through CPUC data request to the IOUs. Generally, do you agree with this proposed guiding principle? Why or why not?***

Vote Solar agrees with the guiding principle that the Public Tool should use the best publicly available data. This will be key for ensuring transparency in the Public Tool, building trust in the analysis therein by allowing stakeholders to check data sources.

12. ***The proposed term of analysis tracks new renewable DG installations out to 2025 and evaluates their useful lifecycle through 2050. Recognizing that the IOU revenue requirements and usage projections in later years will be more uncertain than in early years, rate calculations in later years may utilize revenue requirement and usage "snapshots." The proposed snapshot periods would cover 5 years; revenue requirements and usage would be the same in each year of the snapshot period.***

    a. ***Will this approach adequately describe the economics of program rates in later years? Why or why not?***

b. Are there any other factors that should be considered for the purposes of modeling the IOU's long-term revenue requirements? Please specifically describe each factor and provide a source or an example of its use.

We interpret this question not to mean that the Public Tool will assess costs and benefits of customer-sited renewables only over a five-year period. Rather, we think the question means to suggest that the Public Tool will evaluate DG system lifecycle costs and benefits, but will simplify the data in that lifecycle analysis by fixing revenue requirements and usage data in five-year blocks. If this understanding is correct, we do not object to this simplifying proposal.

As noted our response to Question 6 above, it is critically important that the Public Tool assess impacts over the lifecycle of a renewable DG system, rather than reporting impacts only via a single-year (or likewise a five-year) "snapshot" of net metering costs and benefits.

15. Should the impact of smart inverter technologies paired with DG applications be examined? Why or why not?

Smart inverters can add significant value to solar PV installations and provide benefits to customers and grid operators. A report from the Electric Power Research Institute entitled "Common Functions for Smart Inverters, Version 3 (Technical Update, February 2014)" [7] details a number of potential functions that could be performed by smart inverters, including voltage support, frequency support, anti-islanding, battery storage management, load and generation following (for both PV and PV-paired storage systems), fixed power factor functionality, controlled ramping, price or temperature driven functionality and many others. Many of these functions will provide meaningful grid benefits when a net metered PV system is paired with either a stationary energy storage device or an electric vehicle, mitigating any potential over-

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[7] EPRI report is available at:
http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001026809.

generation and up- or downward ramping needs associated with very high levels of solar PV penetration in the Spring months.

In R. 11-09-011, the three IOUs recently filed a motion with proposed Rule 21 tariff changes for smart inverter capabilities that would become mandatory at the later of December 2015, or whenever the relevant safety standards are approved by Underwriters Laboratories.[8] While standards for the use of smart inverters with customer-sited systems have not yet been finalized, nor values yet quantified for the associated grid benefits, this is an active area of technological and policy development. As noted in Question 12, the Public Tool's proposed term of analysis tracks new renewable DG installations out to 2025 and evaluates their useful lifecycle through 2050; smart inverters may well be significantly deployed in California by 2020. In addition, the Public Tool may be in use as a key tool for cost-benefit analysis by stakeholders and the Commission well after 2015, when smart inverter benefits will be more fully quantified. Vote Solar therefore recommends building functionality for smart inverter capabilities into the Public Tool now, allowing inclusion of values for related benefits and costs at a later date.

19. Should the Public Tool include a cost of service analysis, similar to the 2013 NEM Report? If so, why? If not, why not?

The Public Tool should be capable of calculating customer-generators' cost of service under various tariff options, and determining whether various classes of customer-generators are paying more or less than their cost of service. A cost of service analysis is a simple, meaningful way of estimating whether participating customers will be paying their fair share of costs, and is necessary for an accurate assessment of the true impacts of various successor tariff options.

[8] "Joint Motion of Pacific Gas And Electric Company (U 39 E), Southern California Edison Company (U 338 E) and San Diego Gas & Electric Company (U 902 E) Regarding Implementation of Smart Inverter Functionalities" filed July 18, 2014 in R.11-09-011.

For example, the October 2013 E3 study's cost of service analysis found that in 2011, NEM customers of the three IOUs as a group paid the utilities 103% of what it cost to serve them (though it used outdated rates to arrive at that conclusion).[9] Because of pre-existing cost shifts between various groups of customers, even if there is a net cost to non-participants from a given net metering tariff structure compared with a world in which there is no net metering, participants may still pay the utility more than what it actually costs to serve them because they were overpaying so much to begin with. This broader perspective afforded by cost of service analysis will be crucial for stakeholders, the Commission and the Legislature as we seek to assess the true impacts of net metering and other possible tariff structures.

20. ***To support greater usability of the tool, it may be desirable to limit the number of inputs that a user can modify in the Public Tool. What are the three most important inputs that the user should be able to modify in the Public Tool (e.g., the Resource Balance Year, the cost of carbon, increased RPS procurement, etc.)? Please provide reasons why each input chosen is among the "most important."***

Given the number of factors that play into net metering costs and benefits and the controversy surrounding the correct values to assign to various costs and benefits, we encourage the Commission not to restrict user inputs to a very small number, like three. Some of the many factors that will impact these results will include demand growth, rate design, rate escalation, PV system life, gas price forecasts, and deployment of storage and smart inverters. However, three of the most important modifiable user inputs include the following, all of which are particularly controversial and have a potentially large impact on cost-benefit results.

- **Societal benefits:** Renewable distributed generation (DG) generates a wide range of non-grid specific benefits such as job creation and downstream economic effects, water savings, energy security benefits, and public health improvements and

[9] "California Net Energy Metering Ratepayer Impacts Evaluation," E3, October 2013, pp.9-10.

associated increased welfare and productivity. AB 327 requires the Commission to take into consideration "total benefits… to all customers" (PU Code Section 2827.1(b)(4)), and customers, who are Californians, would certainly be impacted by these types of benefits. We recommend that a user input or series of inputs be available to estimate societal benefits that have not been counted elsewhere in the Public Tool; stakeholders could use public data to estimate and include these benefits.

- **Higher avoided renewables procurement costs:** As noted in response to Question 5, there is a strong likelihood that the state's renewables procurement goals will be increased in coming years, whether via the RPS, a new GHG standard or by some other means. The Public Tool base case should therefore assume a renewable procurement target in excess of 33% by 2025 and increasing in the following years, and should also allow users to modify that target as they see fit.
- **Resource Balance Year:** The Resource Balance Year (RBY) determines in what year the analysis shifts from using short-run avoided costs to long-run avoid costs. 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 demand response as a preferred resource in the state's loading order for electric resources. Renewable 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. However, if the Public Tool does include an RBY, RBY should be a user input so that stakeholder can assess benefits using long-run avoided costs in all years, rather than shifting from short-run to long-run avoided costs at a future RBY.

21. ***Should participating customer-generators be modeled as a separate customer class for cost allocation and rate design purposes? If so, why? If not, why not?***

Participating customers should not be modeled as a separate class for cost allocation and rate design purposes. Not only it is unclear whether it would be legal under AB 327 for the Commission to assign customer-generators to a special rate class, but seeking to model this in the Public Tool would create unnecessary controversy and complexity. It would also be putting the cart before the horse, given that no up-to-date cost-benefit analysis indicates that putting customer-generators into a special rate class will be necessary for properly allocating costs and benefits.

22. ***The following compensation structures are proposed to be included in the Public Tool:***
    - ***NEM structure;***
    - ***Feed-in Tariff (FiT) for only generation exports to the electric grid; and***
    - ***FiT for all system generation.***

    a. ***What, if any, variations to the above compensation structures should be modeled in the Public Tool (e.g., possible variations of NEM could include compensation based on specific components of the underlying rate structure)? Please provide specific reasons for the variations proposed. Provide quantitative examples or illustrations if relevant.***

    b. ***What, if any, other potential compensation mechanisms not mentioned above should be modeled in the Public Tool?***

    c. ***At what frequency, for either NEM or an export-only FiT, should exports be netted against imports in the Public Tool (e.g., hourly or 15-min.)? Please provide specific reasons for your choice of frequency. Include quantitative examples or illustrations if relevant.***

The above list seems adequate, assuming that users could model varying values for the FiT. We support including the ability to model varying the NEM compensation structure by netting out specific components of the rate structure that could change over the system's lifetime, for example netting out a distribution charge from the net metering credit for exports starting in Year 5 of the system's interconnection, or netting out public purpose charges for the full lifetime of the system. We also propose the additional variation of including assignment of interconnection fees to the customer for each of the three compensation structures (i.e. assessing impacts if the current waiver of interconnection fees assigned to customer-generators is removed after the 5% cap is hit).

23. Residential rate designs proposed to be included in the Public Tool are given below. These rates would be applicable to both participating customer-generators and non-participating customers:

- ***a. Existing rate design (e.g. inclining block rate with 4 tiers)***
- ***b. 3-tier non-time of use (TOU) rate***
- ***c. 2-tier (baseline = 50% - 60% of average usage) with geographic baseline quantities***
- ***d. Seasonal TOU (summer 3 periods, winter 2 periods)***
- ***e. 2-tier with seasonal TOU***
- ***f. Marginal cost-based rate components***
- ***g. Option to use a late-shifted summer peak with TOU rates***
- ***h. In combination with above rate components, the implementation of a fixed charge***
- ***i. In combination with above rate components, the implementation of a minimum bill.***

Within the framework set forth above, please describe any specific rate design choices that should be included as options in the Public Tool. Please provide all information necessary for using those choices in the Public Tool. For example, for TOU rates, please specify the hours defining each TOU period; for tiered rates, please specify the block sizes.

The above list proposes to include the existing tiered rate options in the Public Tool, but does not propose the same for the existing TOU rate options. Instead, it includes two base TOU rate options: (i) a seasonal TOU option with three summer and two winter TOU periods and (ii) a 2-tier variation of the seasonal TOU option. These rate options are not consistent with any of the utilities' ongoing TOU rate options. The non-tiered tariff is similar to SDG&E's Schedule DR-SES except that DR-SES also includes a minimum bill charge. The two-tiered rate option is unlike any of the utilities' ongoing rate offerings. PG&E's Schedule E-6 and SDG&E's Schedule DR-TOU are four-tiered TOU rate schedules, which are quite different from the proposed two-tier rate structure. SCE's Schedule TOU-D-T, while two-tiered, has two summer TOU periods, not three. SDG&E's Schedule DR-TOU likewise has just two summer TOU periods and it additionally includes a minimum bill charge.

Vote Solar has recommended in the Residential Rate Design OIR that the four existing TOU rate schedules mentioned above should remain open to new customers with their existing rate structures in place in order to support the continued adoption of solar DG. Under this recommendation, PG&E's Schedule E-6, SDG&E's Schedules DR-SES and DR-TOU, and SCE's Schedule TOU-D-T would not be affected by changes that might affect other residential tariffs, such as new customer charges, changes to tier differentials, changes to TOU differentials, and changes to TOU period definitions. These four tariffs, if kept open consistent with Vote Solar's recommendation, are likely be attractive to new NEM customers. To accurately assess NEM bill impacts, it is therefore important that rate structures consistent with these tariffs be included in the Public Tool.

24. ***The proposed rate design elements that would be applicable only to residential rates of participating customer-generators are:***

    a. ***A grid/network use charge on exports ($/kWh exported, $/nameplate kW per month);***
    b. ***Non-bypassable public purpose charges.***

    Please describe any other residential rate design features applicable only to customer-generators that should be included in the Public Tool. Please provide justifications for your proposal. Be as specific as possible and provide quantitative examples or illustrations if relevant.

We do not support assigning rate design elements specifically and only to customer-generators. As noted the response to Question 22, we do support including the ability to model varying the NEM compensation structure by netting out specific components of the rate structure that could change over the system’s lifetime, for example netting out a distribution charge from the net metering credit for exports starting in Year 5 of the system’s interconnection, or netting out public purpose charges for the full lifetime of the system.

26. ***The proposed rate designs that would be applicable only to non-residential rates of participating customer-generators are:***

    a. ***Rate designs specified in number 25 above plusgrid/network use charge on exports ($/kWh for customers without demand charges or $/kW-month for customers with demand charges);***
    b. ***Rate designs specified in number 25 above with non-bypassable public purpose charge;***
    c. ***For customers with demand charges, standby charge ($/kW-mo).***

    Please describe other non-residential rate design features applicable to only participating customer-generators that should be included in the Public Tool. Please provide justifications for your proposal. Be as specific as possible and provide quantitative examples or illustrations if relevant.

    Please see the response to Question 24.

27. ***Please provide one or more proposals for determining a pricing methodology for a successor tariff that is a FiT. Please provide justifications for your proposals, including but not limited to any examples of existing programs that use your proposed methodology. Please also provide quantitative examples or illustrations if relevant.***

    In proposing your preferred FiT structure, please address at least the following issues:

    a. ***Should the FiT be structured to encourage certain operational characteristics, system designs, or locations (e.g. west-facing systems, etc.)? Potential structures to consider include:***

        i. ***Should there be a TOU variation or seasonal variation to the design? Why or why not? If yes, please propose a structure and rationale for each element of the proposal. Please be as specific as possible, including but not limited to any examples of existing programs that use varying technology types. For example, for TOU rates please specify the hours defining each TOU period; for tiered rates, please specify the block sizes.***

            Please provide quantitative examples or illustrations if relevant.

        ii. ***Should there be a time of delivery (TOD) factor applied to the established FiT rate? Why or why not?***

        iii. ***Should the FiT vary by geography? Why or why not? If yes, please propose a structure and rationale for each element of the proposal, including but not limited to any examples of existing programs that use varying technology types. Please provide quantitative examples or illustrations if relevant.***

b. ***Should the FiT vary by each technology type? Why or why not? If yes, please propose a structure and rationale for each element of the proposal, including but not limited to any examples of existing programs that use varying technology types. Please provide quantitative examples or illustrations if relevant.***

c. ***Should the FiT have a fixed escalator from year to year or other mechanism to adjust the value paid per kWh over the contract term? Please provide specific justifications for your choice, including but not limited to any examples of existing programs that adjust the value paid. Please provide quantitative examples or illustrations if relevant.***

d. ***How frequently should the FiT rate be updated and how? Please provide specific justifications for your choice, including but not limited to any examples of existing programs that use rate updates. Please provide quantitative examples or illustrations if relevant.***

e. ***Please describe in detail the cost data that would be used by your proposal(s) for the FiT. Please include information on public availability, ease of access to the information, frequency of refresh of the data, etc.***

f. ***What other factors or elements should be included in the Public Tool in order to provide adequate representation of your proposal?***

We consider it premature at this time in the proceeding for parties to propose specific feed-in tariff structures, when the key focus should instead be on developing a robust and user-friendly Public Tool. As a general principle, any feed-in tariff should fully compensate customer-generators for the long-run benefits that their generation provides to the grid, ratepayers, and society. In addition, we note that customers nationwide have a PURPA-backed right to generate their own renewable electricity to meet their on-site energy needs.[10] Customers' right to self-generate means they may choose to reduce the amount of power they purchase from their utility, and therefore they cannot legally be *required* to move to a buy all-sell all compensation structure, though the Commission could approve an option for NEM customers who choose to do so. Because customers have a right to self-generate, the Commission may only require changes

[10] The relevant PURPA requirements can be found in 18 CFR §292.303.

to the crediting structure for the energy exported from an on-site generation system, not for the energy used to reduce on-site load.

Date: October 1, 2014

Respectfully submitted,

By: /s/

Susannah Churchill
Regional Director, West Coast
The Vote Solar Initiative