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BEFORE THE ENERGY COMMISSION

OF THE STATE OF CALIFORNIA

Preparation of the 2008 Integrated Energy Policy Report Update and the 2009 Integrated Energy Policy Report	Docket No. 08-IEP-1
and	and
Implementation of Renewables Portfolio Standard Legislation.	Docket No. 03-RPS-1078

COMMENTS OF THE SOLAR ALLIANCE, GREENVOLTS, AND THE CALIFORNIA SOLAR ENERGY INDUSTRIES ASSOCIATION ON 2009 IEPR - FEED-IN TARIFFS

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Date: July 11, 2008

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In accord with the Notice of Staff Workshop: Renewable Energy "Feed-In" Tariffs mailed on June 20, 2008 ("Notice"), the Solar Alliance, GreenVolts, and the California Solar Energy Industries Association ("CAL SEIA") (hereinafter, the "Joint Solar Parties") submit these comments addressing the questions and workshop topics included in the Notice.[1] The Joint Solar Parties appreciate the opportunity to provide these comments to the California Energy Commission ("Commission").

The Solar Alliance is a state-focused association of solar photovoltaic ("PV") manufacturers, integrators, installers, and financiers dedicated to accelerating the deployment of solar electric power in the United States.[2] GreenVolts is the developer of a state-of-the-art

[1] GreenVolts and CAL SEIA have given counsel for the Solar Alliance permission to sign this pleading on their behalf.

[2] Current members of the Solar Alliance include American Solar Electric, Applied Materials, Borrego Solar, BP Solar, Conergy, Dow-Corning, Energy Innovations, Evergreen Solar, First Solar, Kyocera, Mitsubishi Electric, MMA Renewable Ventures, Oerlikon Solar, PPM Energy,

(footnote continued)

concentrating photovoltaic ("CPV") technology that achieves unparalleled solar-to-electricity conversion efficiency through an innovative integration of optics and solar tracking. CAL SEIA is a non-profit trade association intended to increase the use of solar energy in California, and represents over 200 solar companies doing business in California including installation companies, manufacturers, distributors, wholesalers, consultants, engineers, designers, and utilities. Our organizations and members have a strong interest in the adoption and implementation of far-reaching policies and programs that will accelerate the movement toward a low-carbon economy and stimulate the development and use of zero-carbon, renewable energy technologies such as solar technologies. To this end, the creation and implementation of a feed-in tariff has a direct impact on the respective organizations of the Joint Solar Parties.

I. COMMENTS

The Joint Solar Parties offer the following comments with regard to feed-in tariffs in response to some, but not all of the specific questions included in the Notice. The Joint Solar Parties reserve the right to comment at a future date on those questions that it does not specifically address within these comments. The Joint Solar Parties have organized these comments by the specific questions included in the Notice.

A. Question A.1 – Should feed-in tariffs be expanded or limited to projects 20 MW or less?

The Joint Solar Parties support an expansion in feed-in tariff eligibility to include larger systems than the current maximum of 1.5 megawatts ("MW"), and believe that a feed-in tariff should apply to projects up to 20 MW at this time. Currently, California has effective programs for very small or very large solar generators. The California Solar Initiative ("CSI")

REC Solar, Sanyo, Schott Solar, Sharp Solar, SolarCity, Solaria, Solar Power Partners, SolarWorld, SPG Solar, SunEdison, SunPower, Suntech, Tioga Solar, Trinity Solar, Uni-Solar and Xantrex.

provides incentives for systems that serve on-site load up to one megawatt. Most contracts signed by utilities to meet California's Renewable Procurement Standard ("RPS") have been hundreds of megawatts in size. There is a programmatic gap between the CSI and the 20 MW threshold for RPS that could yield a significant contribution of solar generation to meet the RPS.

Southern California Edison's ("SCE") recent application (Application No. 08-03-015) to the California Public Utilities Commission ("CPUC") to install 250 to 500 MW of solar systems in the 1 to 2 MW range on customer rooftops both illustrated the benefits of increasing the amount of distributed generation inside distribution networks, and highlighted the fact that California currently does not have a good policy tool to develop this market. We believe that a feed-in tariff offered for systems up to 20 MW can be that policy tool.

The Joint Solar Parties believe that expanding the feed-in tariff to projects up to 20 MW will offer many benefits to California, not the least of which is an increase in the state's ability to meet its ambitious RPS goals. According to the 2007 Integrated Energy Policy Report ("IEPR"), "[a]n expanded use of feed-in tariffs can stimulate the robust pace of renewable energy development needed to achieve 33 percent renewables by 2020."[3] Accelerated deployment of renewable resources will also enable California to achieve its AB 32 greenhouse gas reduction goals and foster development of clean distributed generation ("DG") in furtherance of the goals articulated in the Commission's Energy Action Plan II.[4]

However, expansion of the feed-in tariff to projects beyond 20 MW should be carefully considered given the experiences of the markets in other countries. There are two variables that have vexed feed-in-tariff markets regarding larger plants. The first is getting the level set high enough so that it encourages market development while avoiding a tariff that is so popular that it

[3] 2007 IEPR at p. 147.

overwhelms available budgets. Germany, Spain and Ontario fall in the latter category and have modified or even temporarily halted their programs. Policy mechanisms that link market penetration to a long-term, transparent tariff rate digression may be able to address this issue.

The other variable to address is how to handle uncoordinated siting of larger systems that can change the dynamics of grid operations outside of the planning cycle for grid investments. At a larger scale, uncoordinated siting may lead to a higher cost of grid investment. For example, in Italy, permits for solar plants are being issued most frequently clustered among a few regions, which is leading to a flood of interconnection requests in those areas. Any policy that does not allow for the sustained, orderly growth of the market, but instead sets up "boom and bust" cycles, will cost more in the aggregate to grow a market. Boom and bust cycles cause market development funds to pay twice for the same end--once before the bust and again after the bust to rebuild momentum lost as a result of the bust. Orderly siting and interconnection of larger utility-scale projects will be a key requirement for solar market penetration, and one that is hard to provide through a traditional feed-in-tariff policy design.

Thus, the Commission must be careful before seeking to expand feed-in tariffs to large projects over 20 MW, though feed-in tariffs should be expanded to projects up to 20 MW at this time.

B. Question A.2 – What are the barriers to renewable resource development that have led to delay or project failure of RPS contracts that feed-in tariffs may overcome?

The use of feed-in tariffs for projects up to 20 MW may overcome a multitude of barriers to renewable resource development including:

[4] *See* California Public Utilities Commission ("CPUC") Decision ("D.") 07-09-040 at p. 119.

1. High transaction costs due to the complexity and time-consuming nature of RPS contracts.

There has been repeated recognition that renewable generators less than 20 megawatts are disadvantaged in utility RPS solicitations. The California Public Utilities Commission ("CPUC") acknowledged this disadvantage when it established its Future Policy and Pricing for Qualifying Facilities in Decision ("D.") 07-09-040. In that decision, the CPUC established certain contract requirements for QFs up to 20 MW in recognition of the fact that "a small QF is unable to bid in a utility RFO, generally does not have the resources or expertise to negotiate with a utility, and is prohibited by current rules from selling surplus generation directly to the CAISO."[5] The CPUC reiterated this concern in its Opinion Conditionally Accepting Procurement Plans for 2008 RPS Solicitations. In that decision, the CPUC recognized that "in order to meet the hundreds of megawatts embedded in the 20% by 2010 objective, utilities primarily need (and generally want) to devote limited time and resources to bid processing and LCBF analysis for larger rather than smaller projects."[6]

SCE has also acknowledged the challenge faced by renewable generators with projects 20 MW or less. In addition to their recent CPUC Application No. 08-03-015 mentioned above, SCE established a Biomass Program in May 2007 that offers standard contracts for biomass projects up to 20 MW. SCE's motivation for establishing this program stemmed in part from recognition that standard offer contracts for small biomass generators were needed to address difficulties smaller biomass projects have in participating in SCE's annual solicitations and to eliminate the complex negotiation process required of larger generators.[7] As stated in the Notice, SCE has 11 MW under contract, another 23 MW in negotiation, and 22 MW of inquiries

[5] CPUC D.07-09-040 at pp. 118-19.
[6] CPUC D.08-02-008 at p. 30.

under its Biomass Program.[8] This response shows that developers of smaller renewable projects respond to simplified procedures for RPS contracting when they are made available.

From a small project developer's perspective, RPS solicitations are costly and involve sorting through complex documents, attending bidders' conferences and/or workshops, preparing documents, and engaging in post-bid negotiations.[9] The smaller a project, the more likely it is that profit margins will be eaten up by the transaction costs associated with participating in an RPS solicitation. This is particularly problematic as investors wishing to undertake a 5 MW, 10 MW or 15 MW project tend to be entities that are relative newcomers to the RPS process and may find them cumbersome. These investors may find the cost of participating in RPS solicitations is not justified when they consider their odds of winning in competition with entities that have much larger resources and more experience in bidding.

Expanded tariff/standard contract eligibility will remedy this problem by ensuring that small renewable generators up to 20 MW have a simplified and streamlined mechanism to sell electricity to a utility without complex negotiations or delay. In addition by setting different payment amounts, a properly designed feed-in tariff or standard contract can recognize the different underlying cost structures of various technologies (including different solar technologies) and their differing benefits to the grid and to energy load management.

2. Difficulty in securing financing for projects because of the lack of certainty regarding variable and negotiable RPS contract terms.

The CPUC's standard QF contracts and SCE's standard biomass contracts exemplify the benefit that contract certainty provides in helping developers finance renewable

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[7] Id. at p. 42.

[8] *See* Notice of Staff Workshop: Renewable Energy "Feed-In" Tariffs, Docket No. 08-IEP-1 and Docket No. 03-RPS-1078, mailed June 20, 2008.

[9] CPUC D.08-02-008 at p. 30.

energy projects that are 20 MW or less. Without this certainty, project financing is contingent on a developer's ability to successfully compete in a utility RPS solicitation and negotiate contract terms that will allow project costs to be financed. Standard contracts offered on a tariffed basis lift this cloud of uncertainty and ensure that small renewable projects can get built. The 2008 IEPR concurs in noting that "[b]y reducing uncertainty in a project's income stream, feed-in tariffs help developers obtain lower cost financing and stimulate investment in a domestic renewable energy market."[10]

3. Transmission-system upgrades are needed to access large-scale renewable resources located far from load.

Feed-in tariffs for projects up to 20 MW incentivize distributed renewable generation that can offer locational benefits and avoid the need for transmission-system upgrades if sited on the distribution system. The expansion of feed-in tariff eligibility up to 20 MW will foster the development of clean distributed generation in furtherance of the goals articulated in the Commission's Energy Action Plan II.[11] Distributed renewable generation has the potential to offer many benefits to California. Distributed generation is strategically located and interconnected in a manner that optimizes delivery to load. As discussed below in Section F, in response to Question A.6, distributed generation offers locational benefits beyond the ability to avoid the transmission system upgrades that currently hamper access to large-scale renewable resources located far from load.

C. Question A.3 – What are the costs and benefits associated with feed-in tariffs for larger projects from the administrator, ratepayer, and societal perspective?

See Section B.1 above, in response to Question A.2.

[10] 2008 IEPR at p. 12.

[11] *See* CPUC D.07-09-040 at p. 119.

D. **Question A.4 – Could feed-in tariffs help increases the mix of renewable energy resources in California and thereby have a dampening effect on electricity price fluctuations?**

The Joint Solar Parties believe that expanded feed-in tariffs can serve as a mechanism to facilitate increased distributed generation projects. This will ensure a greater mix of renewable energy resources in California in the future and, as a result, will provide a dampening effect on electricity price fluctuation.

Presently, developers seeking to deploy innovative grid-scale technologies are at an acute disadvantage in RPS solicitations. As the CPUC noted in D.08-02-008, "the focus of RPS solicitations is largely intended to be on commercially viable projects...."[12] Developers looking to demonstrate the viability of a new renewable energy technology in a small-scale demonstration project face a significant barrier in being able to prove the technological viability of their product. California's current lack of support for these new market entrants raises the possibility of a reduction in technology innovation and a barrier to clean technology investment in the state. By providing a means to bring innovative projects on line in a commercially reasonable fashion, feed-in tariffs will assist in overcoming these obstacles.

E. **Question A.5 – Are feed-in tariffs supported by the same guiding principles used to develop the same RPS procurement process?**

The Commission has stated that the goal of the laws under which it has created its RPS program "is to establish a competitive, self-sustaining renewable energy supply for California while increasing the near-term quantity of renewable energy generated within the state."[13] This guiding principle clearly supports feed-in tariffs as well, for all the reasons described above. In fact, as noted above, the Commission has already declared that the same

[12] CPUC D.08-02-008 at p. 31.

[13] Overall Program Guidebook. CEC-300-2007-003-ED2-CMF, Edition 2 at p. 1.

principles support feed-in tariffs when it noted "[a]n expanded use of feed-in tariffs can stimulate the robust pace of renewable energy development needed to achieve 33 percent renewables by 2020."[14] The Joint Solar Parties believe that feed-in tariffs in California up to 20 MW fulfill a programmatic gap that is currently in the California market.

F. Question A.6 – Can feed-in tariffs be designed to bring down costs over time and limit ratepayer exposure?

The Joint Solar Parties believe that if the costs and benefits of feed-in tariffs are calculated correctly, then feed-in tariffs will bring down costs over time and limit ratepayer exposure. Renewable, wholesale distributed generation ("WDG")[15] projects (which will be able to utilize the feed-in tariffs) promise to provide ratepayers with significant locational benefits compared to large renewable projects that typically must be sited in remote locations where large tracts of land are available. The locational benefits of WDG, which can result in reduced costs, include: (i) increased capacity of distribution transformers at the generation site and at the substation level during peak periods, which reduces line losses and increases transformer life; (ii) avoided distribution system upgrades when DG is located on areas of the distribution grid (or feeders) that are capacity constrained;(iii) avoided transmission system upgrades that are required to access remote renewable resources that are located far from load; (iv) meeting local resource adequacy needs; (v) reducing congestion costs; and (vi) reducing transmission and distribution line losses

Importantly, these economic benefits are not reflected in the current MPR, which is the "brown power" pricing benchmark currently applicable to small renewable generation

[14] 2007 IEPR at p. 147.

[15] "Wholesale distributed generation" (WDG) projects are distinguished from traditional "distributed generation" (DG), which generally refers to small, retail generation projects sized to serve a specific on-site load, with power flowing onto the utility distribution system only to the limited extent that on-site generation happens to exceed on-site load.

projects developed under the CPUC standard offer contracts (up to 1.5 MW) authorized by AB 1969. To date, the MPR has been designed, like the larger RPS program, with a focus on large generation projects that supply many tens or hundreds of megawatts of wholesale power delivered into the bulk transmission system. The MPR today is calculated as the cost of a 500 MW gas-fired combined-cycle power plant sited in California and delivering power to the load center on the CAISO's high-voltage transmission system.

The use of a feed-in tariff structure for small, renewable WDG up to 20 MW would require the Commission to re-examine and to modify the pricing within the feed-in tariff that is applicable to WDG projects. In particular, as discussed further in these comments, the Commission will need to include in the pricing for the tariff/standard contracts the real and quantifiable benefits that ratepayers derive from the favorable location of this new renewable generation. The Commission should not simply assume that the pricing of power from small renewable generators should use the same "brown power" benchmark as large RPS projects interconnected to the CAISO's high voltage transmission grid. By interconnecting on the distribution system close to loads, renewable WDG can avoid additional costs incurred in moving power from the RPS MPR's theoretical 500 MW combined-cycle plant to load.

The pricing applicable to WDG projects will need to be modified in several steps to include the locational benefits of WDG projects. The Joint Solar Parties outline below how and why the MPR should be adjusted when applied to WDG projects.

1. MRTU-based Transmission Losses and Congestion.

Today, the CAISO uses Generation Meter Multipliers ("GMMs") to assess the transmission line loss impacts of each generator on the CAISO transmission grid. A generator's GMM is a measure of its contribution to system average transmission line losses in delivering its power output to a virtual load center. The MPR price is adjusted by the system average GMM, to reflect the delivery of the benchmark CCGT's power to the CAISO load center.[16] Typical RPS contracts pay renewable generators for their generation adjusted by their site-specific GMM, again to reflect delivery to the CAISO load center.

With respect to intra-zonal congestion, such costs are not reflected in prices on the CAISO grid today. Instead, the CAISO relieves such congestion through out-of-market means.

The CAISO's new Market Re-design and Technology Update ("MRTU") program will implement a new system of Locational Marginal Pricing ("LMP"). LMP will provide new data on transmission line loss and congestion costs at thousands of nodes on the CAISO grid. LMP nodal prices will include line loss and congestion components of the market price at each node. The MRTU loss component will reflect the marginal losses at that node; this represents a significant change from the GMM methodology, which uses losses scaled to system average losses. LMP also will provide an explicit valuation of intra-zonal congestion costs at each node. Further, the CAISO will provide aggregated losses and congestion costs across all of the nodes on its system and across each utility's service territory. Thus, for feed-in tariff projects up to 20 MW, it will be possible to determine an MPR adjusted to fit the specific location of each project, reflecting a project's site-specific annual losses and congestion costs under MRTU compared to the system- or utility-average values for these costs.

MRTU is not expected to "go live" until October 2008 at the earliest. Time will be required to ensure that MRTU is working as planned and to accumulate data on site-specific losses and congestion costs under MRTU. However, the Commission should incorporate MRTU line loss and congestion costs into the MPR and into MPR-based prices for

[16] Currently, the system average GMM used in the MPR model is the simple average of the GMMs on the CAISO grid. A pending issue in R. 06-02-012 is whether the 2008 MPR calculation should be revised to use the average GMM weighted by the output of each generator; i.e. the system average loss factor for the CAISO grid.

feed-in tariff projects up to 20 MW, in conjunction with either the 2009 or 2010 MPRs.

2. Distribution Losses.

Small generators located on the distribution system can avoid the distribution line losses specified in the utilities' Wholesale Distribution Access Tariffs ("WDATs"). The CPUC has long recognized this fact with respect to small QFs located on the distribution system.[17] In the QF program, the CPUC generally has looked to the utilities' WDATs as the source for avoided distribution losses.[18] Table 1 below lists the existing WDAT energy loss factors of the three major California IOUs. The MPR applicable to renewable WDG interconnected to the IOUs' distribution systems should be increased by one divided by one minus the distribution loss factors in Table 1, as given by the following formula to reflect the value of these avoided distribution losses:

WDG Distribution Loss Factor = 1 / (1 – WDAT Energy Loss Factor)

Table 1: *Utility WDAT Energy Loss Factors*

Utility	Distribution Voltage	WDAT Energy Loss Factors
PG&E	Primary	1.25%
	Secondary	3.62%
SCE	Subtransmission	1.12%
	Primary	3.73%
SDG&E	All voltages	0%

Sources: PG&E WDAT tariff, CPUC D. 01-01-007for SCE and SDG&E.

For solar projects that produce much of their energy in peak periods, the use of these average distribution loss factors will be a conservative adjustment, as line losses are significantly above the average in peak demand periods when line loadings are the highest.

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[17] *See, e.g.*, CPUC D.82-12-120; CPUC D.84-03-092; CPUC D.87-12-066.

[18] For example, in the CPUC's most recent review of QF line losses – CPUC D.01-01-007 – the CPUC adopted Southern California Edison's and San Diego Gas & Electric's WDAT distribution loss factors as the measure of the distribution line losses avoided by QFs that deliver into the distribution systems of these utilities.

3. Avoided Investment-related T&D Costs.

Small renewable generators can allow the utilities to avoid investments in transmission and distribution ("T&D") facilities. These avoided T&D costs are real and can be quantified using Commission and CPUC-approved methodologies. The CPUC's adopted E3 model for the avoided costs associated with energy efficiency programs includes a time-dependent, hourly valuation of avoided investment-related T&D costs.[19] This model can be used to value the avoided T&D costs from a WDG project, and this value should be added to the MPR that applies to feed-in tariff projects up to 20 MW.

The Joint Solar Parties are aware that the utilities have been reluctant to recognize that generators avoid T&D costs unless a generator is located in an area where specific costs can be avoided.[20] The Joint Solar Parties agree with the March 2008 comments of GreenVolts *et al* at the CPUC concerning the best way forward on this issue: working cooperatively with the IOUs' T&D planners to identify sites that offer <u>greater</u> T&D benefits than the average avoided T&D values produced by the E3 model.[21] Developers of solar WDG would welcome the opportunity to cooperate with the utilities to locate projects at sites on the utility distribution systems where the solar peaking generation provides the greatest benefits for ratepayers, in terms

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[19] The CPUC adopted the E3 model of avoided costs associated with energy efficiency programs in CPUC D.05-04-024.

[20] When the CPUC reviewed the E3 model in 2004 - 2005, the utilities opposed the inclusion of avoided T&D costs in the model, arguing that energy efficiency resources avoid T&D costs only in certain specific, case-by-case circumstances, such as on a rapidly-growing distribution circuit where an upgrade is needed in the near future. The CPUC rejected this position in CPUC D.05-04-024, finding that "while a case-by-case analysis should be applied to determine payments related to specific projects for long-term conservation measures it is appropriate to credit programs with T&D avoided costs for program evaluation purposes." *See* CPUC D.05-04-024 at pp. 35-36.

[21] See Pre-workshop Comments of GreenVolts, Cleantech America, and Community Environmental Council on the 2008 Market Price Referent, CPUC Rulemaking 06-02-012, filed March 6, 2008.

of serving peak period demands and avoiding T&D investments.[22] Projects sited in this cooperative way would receive an adder to their MPR value equal to the expected avoided T&D costs calculated by the adopted E3 model.[23] The avoided T&D costs in the E3 model are average values for each IOU division or planning region. As a result, if renewable WDG is sited in locations with higher-than-average incremental T&D costs, ratepayers would be assured that they have received more-than-full value if the pricing under a tariff/standard contract for such projects includes average avoided T&D costs for that area as an adder to the MPR, as calculated by the E3 model. The comments of GreenVolts *et al* calculated such an adder for each IOU division or planning region included in the E3 model, for both a baseload (7x24) output profile and for a representative solar PV output profile from a south-facing flat-plate PV system at a 38.5 degree tilt located in Sacramento, California. These avoided T&D adders, including separate transmission and distribution components, are reproduced from the March 2008 GreenVolts *et al* filing and are presented in Attachment A.[24]

Actual experience with solar DG developed under the CPUC's Self Generation Incentive Program ("SGIP") is beginning to show that distributed PV systems can reduce peak demands on utility distribution systems. The August 2007 evaluation report on the SGIP program shows that, in the summer of 2006, installed PV systems reduced distribution line

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[22] Obviously, if a project's generating capacity exceeds the capacity of the local distribution system, then the system will need to be upgraded, and the project will incur, rather than avoid, distribution costs.

[23] The Joint Solar Parties recognize there are technical issues which need to be resolved as part of establishing this cooperative process including arriving at technical standards for system sizes for any particular distribution line or circuit. A workshop would be the best forum to discuss these technical issues and work out reasonable solutions in a cooperative fashion.

[24] The E3 model calculates that the solar generation profile produces about 75% of the avoided T&D benefits of the baseload profile, because PV output is high during the peak afternoon hours when peaks occur on the distribution system.

loadings on peak summer afternoons by 42% to 56% of the PV systems' installed capacity.[25] The evaluation consultant, Itron, concluded that "SGIP technologies are seen to provide the potential for significant reduction in peak loading of the distribution system."[26] Itron's report notes a number of the barriers that have prevented SGIP projects from producing an even greater level of capital-related savings on the distribution system:

> In addition to limited penetration of SGIP facilities within the distribution system, a number of other factors contribute to a lack of distribution capital savings. One of these is that the SGIP generators operate independently of the distribution system. Therefore, the SGIP owner does not know when the distribution peak is, nor do they have any incentive to operate during the peak even if they did know. In fact, the current SGIP rules prohibit an additional incentive to operate during the local capacity peak. Similarly, the distribution utility planners do not necessarily know which SGIP generators are being served by overloaded equipment, likely because the penetration of SGIP generators is not currently high enough to warrant close attention for capacity planning at the distribution level. In addition, SGIP owners choose where to install their systems, not the utility; therefore, they are not a concentrated number of installations in a single area of need that could provide significant load relief on a particular overloaded feeder or substation.[27]

The cooperative effort first proposed by GreenVolts *et al* this spring, and supported in these comments, can address all of these important concerns.

G. Questions B and C

The Joint Solar Parties will not comment at this time on the questions posed by the Commission related to design and implementation issues, but reserves the right to do so in the future.

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[25] Some PV technologies track the sun, and thus will sustain higher output than the flat-plate PV profile used in the table over the course of a peak summer afternoon.

[26] Itron, "CPUC Self-Generation Incentive Program – Sixth Year Impact Evaluation Report" (August 30, 2007), at Table 4-1 and pp. 1-10 to 1-14.

[27] Id. at pp. 5-28.

II. CONCLUSION

The Joint Solar Parties appreciate the opportunity to provide these comments addressing issues regarding feed-in tariffs. The Joint Solar Parties believe small renewable generation can contribute meaningfully to RPS procurement if tariff/standard contracts are put in place for each IOU which addresses the needs of small generators up to 20 MW for a consistent, simple, and transparent contract process that also recognizes the benefits wholesale distributed generation can bring to the grid.

Respectfully submitted this July 11, 2008 at San Francisco, California.

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ATTACHMENT A

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E3 Model T&D Values (Levelized 20-year in 2008$)

Utility	Division	Transmission & Distribution: Baseload Profile $/kW-year	Transmission & Distribution: Baseload Profile $/MWh	Transmission & Distribution: Solar Profile $/kW-year	Transmission & Distribution: Solar Profile $/MWh	Transmission-only: Baseload Profile $/kW-year	Transmission-only: Baseload Profile $/MWh	Transmission-only: Solar Profile $/kW-year	Transmission-only: Solar Profile $/MWh	Distribution-only: Baseload Profile $/kW-year	Distribution-only: Baseload Profile $/MWh	Distribution-only: Solar Profile $/kW-year	Distribution-only: Solar Profile $/MWh
PG&E	Central Coast	$46.07	$5.26	$35.70	$24.60	$1.56	$0.18	$1.20	$0.83	$44.51	$5.08	$34.50	$23.77
	De Anza	$58.67	$6.70	$46.95	$32.35	$1.55	$0.18	$1.24	$0.86	$57.11	$6.52	$45.71	$31.49
	Diablo	$55.62	$6.35	$44.51	$30.67	$1.55	$0.18	$1.24	$0.86	$54.06	$6.17	$43.27	$29.81
	East Bay	$11.57	$1.32	$8.97	$6.18	$1.55	$0.18	$1.20	$0.83	$10.02	$1.14	$7.77	$5.35
	Fresno	$48.24	$5.51	$37.08	$25.55	$1.55	$0.18	$1.19	$0.82	$46.68	$5.33	$35.89	$24.72
	Kern	$30.87	$3.52	$23.73	$16.35	$1.56	$0.18	$1.19	$0.82	$29.32	$3.35	$22.54	$15.53
	Los Padres	$46.82	$5.34	$37.47	$25.81	$1.55	$0.18	$1.24	$0.86	$45.26	$5.17	$36.23	$24.96
	Mission	$70.36	$8.03	$54.53	$37.57	$1.55	$0.18	$1.20	$0.83	$68.80	$7.85	$53.32	$36.74
	North Bay	$47.46	$5.42	$36.78	$25.34	$1.55	$0.18	$1.21	$0.83	$45.90	$5.24	$35.57	$24.51
	North Coast	$64.43	$7.35	$40.41	$27.84	$1.56	$0.18	$0.97	$0.67	$62.87	$7.18	$39.43	$27.17
	North Valley	$80.30	$9.17	$63.33	$43.63	$1.55	$0.18	$1.23	$0.84	$78.74	$8.99	$62.10	$42.78
	Peninsula	$20.90	$2.39	$16.19	$11.16	$1.55	$0.18	$1.20	$0.83	$19.34	$2.21	$14.99	$10.33
	Sacramento	$60.93	$6.96	$48.05	$33.11	$1.55	$0.18	$1.23	$0.84	$59.37	$6.78	$46.83	$32.26
	San Francisco	$16.89	$1.93	$13.09	$9.02	$1.56	$0.18	$1.20	$0.83	$15.34	$1.75	$11.89	$8.19
	San Jose	$44.65	$5.10	$35.74	$24.62	$1.55	$0.18	$1.24	$0.86	$43.10	$4.92	$34.49	$23.76
	Sierra	$66.84	$7.63	$52.71	$36.32	$1.55	$0.18	$1.23	$0.84	$65.29	$7.45	$51.49	$35.47
	Stockton	$69.90	$7.98	$56.94	$38.54	$1.56	$0.18	$1.24	$0.86	$68.34	$7.80	$54.69	$37.68
	Yosemite	$42.73	$4.88	$34.20	$23.56	$1.55	$0.18	$1.24	$0.86	$41.18	$4.70	$32.96	$22.70
SCE	Dominguez Hills	$45.91	$5.24	$32.93	$22.69	$26.09	$2.98	$18.71	$12.89	$19.82	$2.26	$14.21	$9.79
	Foothills	$59.90	$6.84	$42.96	$29.59	$26.09	$2.98	$18.71	$12.89	$33.80	$3.86	$24.24	$16.70
	Santa Ana	$55.19	$6.30	$39.58	$27.27	$26.09	$2.98	$18.71	$12.89	$29.10	$3.32	$20.87	$14.38
	SCE Rural	$72.95	$8.33	$53.87	$37.11	$26.09	$2.98	$19.27	$13.27	$46.86	$5.35	$34.60	$23.84
	Ventura	$57.57	$6.57	$41.29	$28.45	$26.09	$2.98	$18.71	$12.89	$31.48	$3.59	$22.58	$15.56
SDG&E	SDG&E	$114.15	$13.03	$84.35	$58.11	$13.84	$1.58	$10.23	$7.05	$100.31	$11.45	$74.12	$51.07

Note: assumes 2008 - 2027 project lifespan, 2.5% inflation, 8.93% discount rate, and 2008 $.