BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

In the Matter of the Application of SOUTHERN CALIFORNIA EDISON COMPANY (U338E) for a Permit to Construct Electrical Facilities: Colorado River Substation Expansion Project.	**Application 10-11-005 (Filed November 3, 2010)**

CALIFORNIANS FOR RENEWABLE ENERGY'S INITIAL COMMENTS ON SUPPLEMENTAL DRAFT ENVIRONMENTAL IMPACT REPORT FOR COLORADO RIVER SUBSTATION EXPANSION

(California SCH 2005101104)

Date: April 8, 2011.

Submitted by:

BRIGGS LAW CORPORATION [file: 1190.10]
Cory J. Briggs
99 East "C" Street, Suite 111
Upland, CA 91786
Telephone: 909-949-7115
Facsimile: 909-949-7121
E-mail: service@briggslawcorp.com

Attorneys for CAlifornians for Renewable Energy

CAlifornians for Renewable Energy now respectfully submits the following initial comments on the supplemental draft environmental impact report for the Colorado River Substation Expansion (California SCH 2005101104). The initial comments are from Bill Powers, P.E., and Robert M. Sarvey and are attached hereto as Exhibits 1 and 2, respectively.

Date: April 8, 2011.

Submitted by: BRIGGS LAW CORPORATION

By: s/ Cory J. Briggs
Cory J. Briggs

VERIFICATION

I am the attorney for CAlifornians for Renewable Energy ("CARE") in this proceeding. My client is absent from the County of San Bernardino, California, where my office is located. I make this verification on behalf of my client for that reason.

The factual statements in the foregoing document and attachments hereto are true of my own knowledge or based on information and belief, and as to those matters I believe them to be true.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Date: April 8, 2011. s/ Cory J. Briggs

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(California SCH 2005101104)

Exhibit 1

ON BEHALF OF CALIFORNIANS FOR RENEWABLE ENERGY

COMMENTS OF BILL POWERS, P.E.

ON DEVERS TO PALO VERDE 2 TRANSMISSION LINE DRAFT SUPPLEMENTAL EIR

April 8, 2011

Bill Powers, P.E.
Powers Engineering
4452 Park Blvd., Suite 209
San Diego, CA 92116
Direct: 619-295-2072
Fax: 619-295-2073
bpowers@powersengineering.com

I. Introduction

I am a registered professional mechanical engineer in California with over 25 years of experience in the energy and environmental fields. I have permitted five 50 MW peaking turbine installations in California, as well as numerous gas turbine, microturbine, and engine cogeneration plants around the state. I organized conferences on permitting gas turbine power plants (2001) and dry cooling systems for power plants (2002) as chair of the San Diego Chapter of the Air & Waste Management Association. I am the author of the October 2007 strategic energy plan for the San Diego region titled "San Diego Smart Energy 2020." The plan uses the state's Energy Action Plan as the framework for accelerated introduction of local renewable and cogeneration distributed resources to reduce greenhouse gas emissions from power generation in the San Diego region by 50 percent by 2020. I am the author of several articles in Natural Gas & Electricity Journal on use of large-scale distributed solar PV in urban areas as a cost-effective substitute for new gas turbine peaking capacity and large, remote solar power plants.

My comments address: 1) the inadequate analysis of the distributed photovoltaic (PV) alternative to Devers to Palo Verde 2 Transmission Project (DPV2) project in the February 2011 DPV2 Draft Supplemental EIR and 2) the proposed Westlands Water District Competitive Renewable Energy Zone, located on retired farmland in the Central Valley and served by 5,000 MW of existing transmission capacity, as a superior location for the 1,250 MW of solar capacity that the DPV2 transmission line is proposed to serve.

The DPV2 Draft Supplemental EIR makes no pretense of evaluating a non-transmission alternative to DPV2. The Draft Supplemental EIR simply states (p. C-16):

"The No Project Alternative scenario is the circumstance under which the Proposed Project does not proceed. (CEQA Guidelines §15126.6(e)(3)(B).) The analysis of the No Project Alternative compares the environmental effects of the property remaining in its existing state, against environmental effects which would occur if the Proposed Project is approved.

Disapproval of the Proposed Project would likely lead SCE and/or the solar project developers to pursue other actions to achieve the objectives of the Proposed Project. The events or actions that are reasonably expected to occur in the foreseeable future without the CRS expansion include the following:

- The approved 500 kV transmission from Colorado River Substation to Devers Substation would be constructed as already approved by the CPUC (and as anticipated to be approved by the BLM).

- The approved solar power projects (1,000 MW Blythe Solar Power Project - BSPP and 250 MW Genesis Solar Energy Project - GSEP) would have substantial delays in their online dates because their projects would have to be redesigned and the changes re-evaluated under CEQA and NEPA due to the need for substantially larger and more inefficient infrastructure. Specifically:

- The BSPP project would likely have to be redesigned to incorporate a larger onsite substation and a 500 kV gentie line, rather than a 230 kV gentie line to the expanded CRS substation, in order for BSPP to interconnect to the regional transmission system. The additional cost of this larger substation and the delays associated with CEQA and NEPA review of the changes may affect the financial viability of the project and its ability to qualify for financing.

- The approved GSEP project would use an existing 230 kV transmission line along much of the route between the Genesis solar project site and the CRS. In the No Project scenario, both a larger onsite substation and a new, additional 500 kV line would have to be installed (rather than the current approved plan, which would require only installation of a second circuit onto existing 230 kV towers)."

There is no analysis of non-transmission alternatives in the DPV2 Draft Supplemental EIR. The construction of BSPP and GSEP are assumed to be inevitable, despite both projects being subject to National Historic Preservation Act Section 106 lawsuits. In contrast, the Draft and October 2008 Final EIR/EIS prepared by the California Public Utilities Commission (CPUC) and Bureau of Land Management (BLM) for San Diego Gas & Electric's (SDG&E) proposed Sunrise Powerlink transmission line includes voluminous analysis of multiple non-transmission alternatives to the proposed project. See the complete Sunrise Powerlink Final EIS/EIS at: http://www.cpuc.ca.gov/environment/info/aspen/sunrise/toc-feir.htm.

The conclusion of the CPUC/BLM Final EIR/EIS for the Sunrise Powerlink was that either of the two non-transmission in-basin alternatives was environmentally superior to the proposed project or any transmission alternative to the proposed project. The DPV2 Draft Supplemental EIR avoids a similar conclusion by failing to analyze any non-transmission alternative to DPV2.

The failure of the DPV2 Draft Supplemental EIR to analyze non-transmission alternatives is a substantial omission. SCE is already constructing a 500 MW distributed PV project. Distributed PV is clearly a viable non-transmission alternative. The major controversy surrounding both BSPP and GSEP is the use of undeveloped public lands for these projects. There are hundreds of thousands of acres of retired agricultural lands and brownfields in the Mojave Desert and Central Valley located on or near existing transmission lines. Comments by Powers Engineering on the CEC's June 2010 Revised Staff Assessment (RSA) for the GSEP are used as a case study in this comment letter to demonstrate the cost and siting advantages of non-transmission alternatives to DPV2.

II. Rooftop PV Is at the Top of the Energy Action Plan Loading Order

The California Energy Commission (CEC), in discussing the conservation and demand-side management alternative to solar thermal projects in the Mojave Desert such as ISEGS and GSEP, that cost-effective energy efficiency is the resource of first choice in meeting California's energy needs (p. B.2-84, GSEP Revised Staff Assessment - RSA):

"Conservation and demand-side management consist of a variety of approaches to reduce of electricity use, including energy efficiency and conservation, building and appliance standards, and load management and fuel substitution. In 2005 the Energy Commission and CPUC's Energy Action Plan II declared cost effective energy efficiency as the resource of first choice for meeting California's energy needs."

The CEC and the CPUC developed the "Energy Action Plan" in 2003 to guide strategic energy decisionmaking in California. The Energy Action Plan establishes the energy resource "loading order," or priority list that defines how California's energy needs are to be met. Energy Action Plan I was published in May 2003.[1] Energy Action Plan I describes the loading order in the following manner (p. 4):

"The Action Plan envisions a "loading order" of energy resources that will guide decisions made by the agencies jointly and singly. First, the agencies want to optimize all strategies for increasing conservation and energy efficiency to minimize increases in electricity and natural gas demand. Second, recognizing that new generation is both necessary and desirable, the agencies would like to see these needs met first by renewable energy resources and distributed generation. Third, because the preferred resources require both sufficient investment and adequate time to "get to scale," the agencies also will support additional clean, fossil fuel, central-station generation. Simultaneously, the agencies intend to improve the bulk electricity transmission grid and distribution facility infrastructure to support growing demand centers and the interconnection of new generation."

Energy Action Plan I, Under "Optimize Energy Conservation and Resource Efficiency," states (p. 5):

"Incorporate distributed generation or renewable technologies into energy efficiency standards for new building construction."

Energy Action Plan I identifies rooftop PV as a de facto energy efficiency measure with this statement. As noted in the GSEP RSA (p. B.2-84), energy efficiency is at the top of the loading order. Energy Action Plan I also states, Under "Promote Customer and Utility-Owned Distributed Generation," (p. 7):

"Distributed generation is an important local resource that can enhance reliability and provide high quality power, without compromising environmental quality. The state is

[1] Energy Action Plan I: http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF

promoting and encouraging clean and renewable customer and utility owned distributed generation as a key component of its energy system. Clean distributed generation should enhance the state's environmental goals. This determined and aggressive commitment to efficient, clean and renewable energy resources will provide vision and leadership to others seeking to enhance environmental quality and moderate energy sector impacts on climate change. Such resources, by their characteristics, are virtually guaranteed to serve California load. With proper inducements distributed generation will become economic.

- Promote clean, small generation resources located at load centers.
- Determine system benefits of distributed generation and related costs.
- Develop standards so that renewable distributed generation may participate in the Renewable Portfolio Standard program."

Energy Action Plan I prioritizes rooftop PV as the preferable renewable resource, but indicates obliquely that it is costly and that in any case distributed PV is not eligible to participate in the Renewable Portfolio Standard (RPS) program. Therefore investor-owned utilities have no incentive to develop distributed PV resources. Since Energy Action Plan I was approved in 2003, PV cost has dropped dramatically. Commercial distributed PV is half the cost it was in 2003 and costs continue to drop. Residential PV is following quickly behind. Distributed PV is also now eligible for the RPS program.[2]

Energy Action Plan II was adopted in September 2005.[3] The purpose of Energy Action Plan II is stated as (p. 1): "EAP II is intended to look forward to the actions needed in California over the next few years, and to refine and strengthen the foundation prepared by EAP I." Energy Action Plan II reaffirms the loading order stating (p. 2):

> "EAP II continues the strong support for the loading order – endorsed by Governor Schwarzenegger – that describes the priority sequence for actions to address increasing energy needs. The loading order identifies energy efficiency and demand response as

[2] CPUC Press Release – Docket A.08-03-015, *CPUC Approves Edison Solar Roof Program*, June 18, 2009. "The energy generated from the project will be used to serve Edison's retail customers and the output from these facilities will be counted towards Edison's RPS goals."
[3] Energy Action Plan II: http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF

the State's preferred means of meeting growing energy needs. After cost-effective efficiency and demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications. To the extent efficiency, demand response, renewable resources, and distributed generation are unable to satisfy increasing energy and capacity needs, we support clean and efficient fossil-fired generation."

The CEC's *2009 Integrated Energy Policy Report (IEPR) – Final Committee Report* (December 2009), underscores the integration of building PV as a critical component of "net zero" energy use targets for new residential and commercial construction, under the heading "Energy Efficiency and the Environment," explaining:[4]

"With the focus on reducing GHG emissions in the electricity sector, energy efficiency takes center stage as a zero emissions strategy. One of the primary strategies to reduce GHG emissions through energy efficiency is the concept of zero net energy buildings. In the 2007 IEPR, the Energy Commission recommended increasing the efficiency standards for buildings so that, when combined with on-site generation, newly constructed buildings could be zero net energy by 2020 for residences and by 2030 for commercial buildings.

A zero net energy building merges highly energy efficient building construction and state-of-the-art appliances and lighting systems to reduce a building's load and peak requirements and includes on-site renewable energy such as solar PV to meet remaining energy needs. The result is a grid-connected building that draws energy from, and feeds surplus energy to, the grid. The goal is for the building to use net zero energy over the year."

The GSEP RSA acknowledges the state's commitment to net zero residential and commercial buildings, stating (RSA, p. B.2-84):

"The CPUC, with support from the Governor's Office, the Energy Commission, and the California Air Resources Board, among others, adopted the California Long-Term

[4] CEC, *2009 Integrated Energy Policy Report (IEPR) – Final Committee Report*, December 2009, p. 56.

Energy Efficiency Strategy Plan for 2009 to 2020 in September 2008 (CPUC 2008). The plan is a framework for all sectors in California including industry, agriculture, large and small businesses, and households. Major goals of the plan include:

- All new residential construction will be zero net energy by 2020;
- All new commercial construction will be zero net energy by 2030;
- Heating, ventilation, and air conditioning industries will be re-shaped to deliver maximum performance systems;
- Eligible low-income customers will be able to participate in the Low Income Energy Efficiency program and will be provided with cost-effective energy efficiency measures in their residences by 2020."

The GSEP RSA is flawed in its failure to identify rooftop PV as a higher priority in the Energy Action Plan loading order, and California's long-term energy efficiency strategy plan, than utility-scale remote solar resources like GSEP. Rooftop (or parking lot) distributed PV is an integral component of the long-term energy efficiency strategy plan adopted by the CPUC in 2008. Energy Action Plan II declares cost-effective energy efficiency as the resource of first choice for meeting California's energy needs. The CEC rejection of distributed PV as a superior alternative to the proposed GSEP solar thermal projects ignores the integral role of distributed PV in the CEC's own definition of energy efficiency and net zero buildings in the 2009 IEPR.

III. GSEP RSA Rationale for Eliminating Rooftop PV is Flawed

The GSEP RSA correctly describes that a distributed rooftop PV alternative has essentially no environmental impact, stating (p. B.2-68):

- Distributed solar PV is assumed to be located on already existing structures or disturbed areas so little to no new ground disturbance would be required and there would be few associated biological impacts.

- Relatively minimal maintenance and washing of the solar panels would be required.

- Because most PV panels are black to absorb sun, rather than mirrored to reflect it, glare would be minimal relative to reflective technologies (like GSEP)

- Additionally, the distributed solar PV alternative would not require the additional operational components, such as dry-cooling towers, substations, transmission interconnection, maintenance and operation facilities with corresponding visual impacts.

The GSEP RSA then eliminates distributed PV, citing a number of reasons why achieving 250 MW of distributed PV is not a feasible substitute for GSEP (RSA, p. B.2-69):

- Would require accelerated deployment of distributed PV at more than double the historic rate of deployment under the California Solar Initiative.

- Would require lower PV cost - distributed PV is higher cost than central station solar thermal.

- Integrating large amounts of distributed PV on distribution systems throughout California presents challenges – will require development of a new transparent distribution planning framework.

Each of these justifications for elimination of distributed PV is flawed, as explained in the following paragraphs.

A. Distributed PV Is Already Being Deployed at a Much Faster Rate in California than Central Station Solar Thermal

The GSEP RSA notes that more than 540 MW of distributed PV was in operation in California through May 2009, and that the PV installation rate doubled between 2008 and 2007. California has approximately 360 MW of installed solar thermal capacity as of June 2010. With the exception of the 5 MW eSolar power tower demonstration project that came online in 2009 (p. B.2-68), all of this solar thermal capacity was installed between 1984 and 1990.[5]

The GSEP RSA correctly describes that both SCE and PG&E, the two largest investor-owned utilities (IOU) in California, are constructing large distributed PV projects (p. B.2-67). SDG&E has a much smaller distributed PV project in development. The 500 MW SCE urban PV project was approved by the CPUC in June 2009. The 500 MW PG&E distributed PV project was approved by the CPUC in April 2010. These projects are RPS-eligible and will consist of a 250 MW IOU-owned component and a 250 MW third-party component. The power purchase agreement (PPA) between GSEP and PG&E is same type of contract mechanism that will be used by SCE and PG&E to contract for the 250 MW third-party component of their respective distributed PV projects.

Progress in distributed PV installation rates under the California Solar Initiative (CSI) program provides no insight into the ability of the solar industry to carry-out multiple large-scale distributed PV projects simultaneously, in the range of 250 to 500 MW each, in California. The CSI program is not the vehicle that will be used to build these projects. These projects will be built under long-term PPAs between the distributed PV project developer and a utility within the framework of the RPS program.

An example is the PPA between PG&E and Sempra Generation for 10 MW of fixed thin-film PV in Nevada.[6] Sempra Resources is the holding company that owns both Sempra Generation and SDG&E. The PG&E/Sempra PPA is a technology-differentiated renewable energy contract at a price incrementally higher than the market price referent (MPR) to assure that the project developer, Sempra Generation, makes a reasonable return on its investment. The contract is in effect the equivalent of a technology differentiated feed-in tariff for solar power. No incentives beyond the federal investment tax credit and accelerated depreciation available to any solar energy project were necessary. No incentives beyond those already available would be necessary to build 250 MW of distributed PV under a long-term PPA to substitute for GSEP.

[5] CEC, Large Solar Energy Projects webpage: http://www.energy.ca.gov/siting/solar/index.html
[6] CPUC Resolution E-4240, *Approval of a power purchase agreement (PPA) for generation from a new solar photovoltaic facility between PG&E and El Dorado Energy*, LLC (Sempra Generation), May 18, 2009.

Sempra Generation touts the cost of power generated by its 10 MW PV installation in Nevada as “the lowest cost solar energy in the world.”[7] The company specifically mentions solar thermal projects like GSEP as producing higher-cost solar energy and being commercially unproven, stating:[8]

“Sempra has also evaluated solar thermal power technologies, which use a field of mirrors to concentrate the sunlight to produce heat for electricity generation. The company has found that using solar panels is the cheaper option, (CEO) Allman said. He noted that some of the solar thermal power technologies, such as the use of a central tower for harvesting the heat and generating steam, have yet to be proven commercially.”

SCE has a similar RPS-eligible PPA with NRG for the output of a 21 MW fixed thin-film PV array in Blythe, California.[9] This project began operation in December 2009.

B. IOUs and California’s Energy Policy Makers Acknowledge the Obvious Benefits of Large-Scale Distributed PV Projects as a Direct Complement/Substitute for Remote Central Station Renewable Energy and Associated Transmission

SCE expressed confidence in its March 2008 application to the CPUC for a 250 to 500 MW urban PV project that it can absorb thousands of MW of distributed PV without additional distribution substation infrastructure, stating “SCE’s Solar PV Program is targeted at the vast untapped resource of commercial and industrial rooftop space in SCE’s service territory”[10] and “SCE has identified numerous potential (rooftop) leasing partners whose portfolios contain several times the amount of roof space needed for even the 500 MW program.”[11]

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[7] GreenTech Media, *Sempra Wants 300 MW Plus of Solar in Arizona*, April 22, 2009. "The electricity we are getting out of the 10-megawatt is the lowest cost solar energy ever generated from anywhere in the world.” (CEO Michael Allman).
[8] Ibid.
[9] First Solar press release, *First Solar Sells California Solar Power Project to NRG*, November 23, 2009.
[10] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Application*, March 27, 2008, p. 6.
[11] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Testimony*, March 27, 2008, p. 44.

SCE stated it has the ability to balance loads at the distribution substation level to avoid having to add additional distribution infrastructure to handle this large influx of distributed PV power.[12] SCE explains:

"SCE can coordinate the Solar PV Program with customer demand shifting using existing SCE demand reduction programs on the same circuit. This will create more fully utilized distribution circuit assets. Without such coordination, much more distribution equipment may be needed to increase solar PV deployment. SCE is uniquely situated to combine solar PV Program generation, customer demand programs, and advanced distribution circuit design and operation into one unified system. This is more cost-effective than separate and uncoordinated deployment of each element on separate circuits."[13]

SCE also notes that it will be able to remotely control the output from individual PV arrays to prevent overloading distribution substations or affecting grid reliability:[14]

"The inverter can be configured with custom software to be remotely controlled. This would allow SCE to change the system output based on circuit loads or weather conditions."

As SCE states, "Because these installations will interconnect at the distribution level, they can be brought on line relatively quickly without the need to plan, permit, and construct the transmission lines."[15] This statement was repeated and expanded in the CPUC's June 18, 2009 press release regarding its approval of the 500 MW SCE urban PV project:[16]

Added Commissioner John A. Bohn, author of the decision, "This decision is a major step forward in diversifying the mix of renewable resources in California and spurring the development of a new market niche for large scale rooftop solar applications. Unlike other generation resources, these projects can get built quickly and without the need for expensive new transmission lines. And since they are built on existing structures, these

[12] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Application*, March 27, 2008, pp. 8-9.
[13] Ibid, p. 9.
[14] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Testimony*, March 27, 2008, p. 27.
[15] Ibid, p. 6.
[16] CPUC Press Release – Docket A.08-03-015, *CPUC Approves Edison Solar Roof Program*, June 18, 2009.

projects are extremely benign from an environmental standpoint, with neither land use, water, or air emission impacts. By authorizing both utility-owned and private development of these projects we hope to get the best from both types of ownership structures, promoting competition as well as fostering the rapid development of this nascent market."

The CPUC made a similar observation with its approval of the PG&E 500 MW distributed PV project in April 2010:[17]

"This solar development program has many benefits and can help the state meet its aggressive renewable power goals," said CPUC President Michael R. Peevey. "Smaller scale projects can avoid many of the pitfalls that have plagued larger renewable projects in California, including permitting and transmission challenges. Because of this, programs targeting these resources can serve as a valuable complement to the existing Renewables Portfolio Standard program."

The use of the term "smaller scale" in the CPUC press release is a misnomer. Clearly a 500 MW distributed PV project is larger-scale than the 250 MW GSEP solar thermal project. Individual rooftop PV arrays in a large distributed PV project are functionally equivalent to single rows of reflective mirrors in a solar thermal project. Each rooftop or row is a small contributor to a much bigger whole.

C. IOUs Need Only Provide a Basic Level of Existing Information on Individual IOU Substation Capacities to PV Developers to Interconnect Over 13,000 MW of Distributed PV with Minimal Interconnection Cost

The CPUC has also calculated, for the entire inventory of approximately 1,700 existing IOU substations, the amount of distributed PV that could be accommodated with minimal interconnection cost based on the following reasoning:[18]

[17] CPUC Press Release – Docket A.09-02-019, *CPUC Approves Solar PV Program for PG&E*, April 22, 2010.

[18] CPUC Rulemaking R.08-08-009 – California RPS Program, Administrative Law Judge's Ruling on Additional Commission Consideration of a Feed-In Tariff, *Attachment A - Energy Division FIT Staff Proposal*, March 27, 2009, p. 15.

"Rule 21 specifies maximum generator size relative to the peak load on the load at the point of interconnection at 15%. So, for example, if a generator is interconnected on the low side of a distribution substation bank with a peak load of 20 MW, the maximum Rule 21 interconnection criteria would allow a 3 MW system (3 MW = 15% * 20 MW).

However, the 15% criterion, which is established for all generators regardless of type, was adjusted to 30% for the purposes of determining the technical potential of PV. The 15% limit is established at a level where it is unlikely the generator would have a greater output than the load at the line segment, even in the lowest load hours in the off-peak hours and seasons (such as the middle of the night and in the spring). Since the peak output for photovoltaics is during the middle of the day, PV is unlikely to have any output when loads are lowest. Therefore, a 30% criterion was used for technical interconnection potential estimates. The discussion was held with utility distribution engineers, however, we did not consider formal engineering studies or Rule 21 committee deliberation since the purpose of the analysis was only to define potential."

As a component of the DG FIT development process, the CPUC requested data on peak loads at all IOU substations from the IOUs and compiled that information graphically as shown in Figure 1. According to the CPUC, this data was obtained from IOU distribution engineers.[19] I calculate that approximately 13,300 MW of PV can be connected directly to IOU substation load banks based on the data in Figure 1. The supporting calculations for this estimate are provided in Table 1.

The IOUs provide about two-thirds of electric power supplied in California, with publicly-owned utilities like the Los Angeles Department of Water & Power and the Sacramento Municipal Utility District and others providing the rest.[20] Assuming the substation capacity pattern in Figure 1 is also representative of the non-IOU substations, the total California-wide PV that could be interconnected at substation low-side load banks with no substantive substation upgrades would be [13,300/(2/3)] = 19,950 MW.

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[19] CPUC Rulemaking R.08-08-009 – California RPS Program, Administrative Law Judge's Ruling on Additional Commission Consideration of a Feed-In Tariff, *Attachment A - Energy Division FIT Staff Proposal*, March 27, 2009, pp. 15-16.
[20] CEC, *2007 Integrated Energy Policy Report*, December 2007, Figure 1-11, p. 27.

Figure 1. IOU Substation Peak Loads, 30% of Peak Load, and 10 MW Reference Line

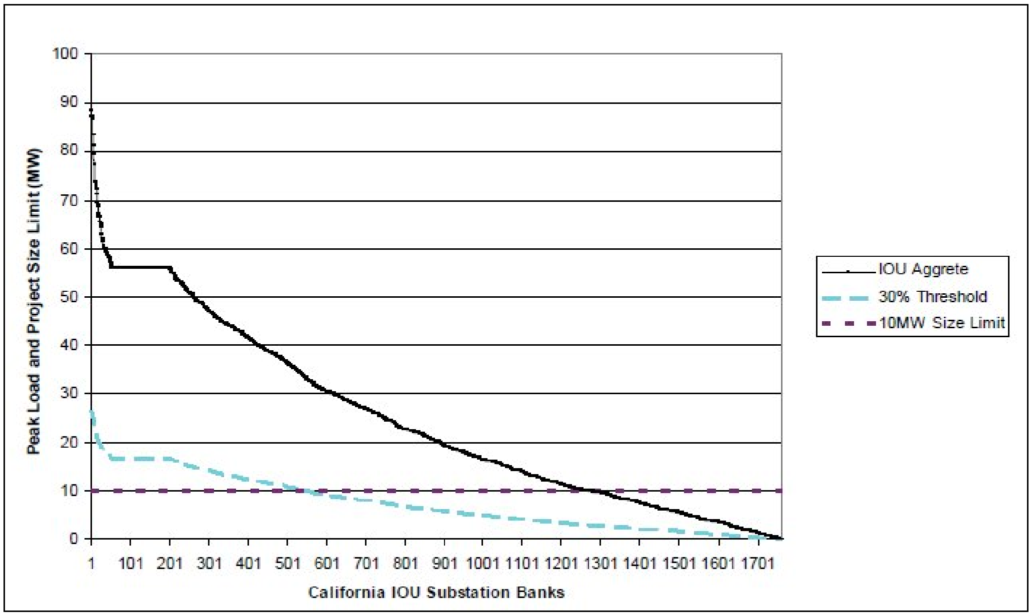

Table 1. Calculation of Distributed PV Interconnection Capacity to Existing IOU Substations with Minimal Interconnection Cost from Data in Figure 1

Substation range	Number of substations	Calculation of distributed PV that could be interconnected with minimal substation upgrades (MW)	Total distributed PV potential (MW)
1-200	200	average peak ~60 MW x 0.30 = 18 MW	3,600
201-500	300	average peak ~45 MW x 0.30 = 13.5 M	4,000
501-800	300	average peak ~30 MW x 0.30 = 9 MW	2,700
801-1,000	200	average peak ~20 MW x 0.30 = 6 MW	1,200
1,001-1,600	600	average peak ~10 MW x 0.30 = 3 MW	1,800
		Distributed PV total:	13,300

In sum, approximately 20,000 MW of distributed PV interconnection capacity is available now in California that would require little or no substation upgrading to accommodate the PV.

D. Cost to Upgrade Existing Distribution Substations and Associated Distribution Feeders to Maximize Distributed PV Deployment is Minimal

An upgrade at the substation would be necessary to accommodate the higher power flows in cases where distributed PV, concentrated on clusters of large rooftops, could provide up to 100 percent of a single substation's peak load. A typical 12 kV/69 kV substation can be upgraded to allow two-way (bidirectional) power flows for up to 100 MW of interconnected distributed PV. SDG&E estimates the cost to build a new 12 kV/69 kV substation is $25 million.[21]

The upgrades necessary to allow problem-free bidirectional power flow across an existing substation is far less than the cost of a new substation. The upgrade would consist of retrofitting substation metering and protective equipment from one-way power flow to bidirectional power flow. The cost of such an upgrade for a typical 100 MW distribution

[21] Ibid, p. 5.21.

substation would be approximately $500,000.[22] This is well under 1 percent of the gross capital cost of 100 MW of state-of-the-art PV at 2010 prices.

Even the cost of a new 100 MW distribution substation, at $25 million, is less than 10 percent of the gross capital cost of 100 MW of state-of-the-art PV at 2010 prices. The substation upgrade cost would be relatively minor compared to the gross capital cost of 100 MW of PV arrays, and would not present a substantive financial hurdle to developing a 100 MW distributed PV resource concentrated in an area served by a single existing substation.

The 2007 IEPR makes clear that incorporating bidirectional capability into distribution substation is a commonsense need in a smart grid environment where higher-and-higher levels of distributed generation are encouraged and expected:[23]

"Utilities spend approximately three-fourths of their total capital budgets on distribution assets, with about two-thirds spent on upgrades and new infrastructure in most years. These investments will remain for 20 to 30 or more years. As utilities throughout the state plan to build new distribution assets and replace old assets, the magnitude of these investments suggests that the state must understand what it is investing in and whether these investments will result in a distribution system that will serve customers in the future. Planning for investment in these assets should include requiring utilities, before undertaking investments in non-advanced grid technologies, to demonstrate that alternative investments in advanced grid technologies that will support grid flexibility have been considered, including from a standpoint of cost effectiveness."

The CPUC assumes that larger PV arrays will be connected directly to the substation low-side (12 kV) load bank. SDG&E estimated that the cost of a 10 MW feeder is $0.6 million

[22] E-mail from M. Martyak, PowerSecure (www.powersecure.com), to B. Powers, Powers Engineering, January 13, 2010. Approximate cost to upgrade older 100 MW distribution substation to full bidirectional flow, assuming four 25 MW load banks with four circuit breakers each (16 total), would be $400,000 to $450,000.
[23] CEC, *2007 Integrated Energy Policy Report*, December 2007, pp. 155-156.

per mile.[24] The cost of a 3-mile long dedicated feeder from multiple rooftop PV arrays with a combined capacity of 10 MW to the low-side bus of the substation would be less than $2 million based on SDG&E's cost estimate.

The current capital cost for state-of-the-art commercial rooftop PV is approximately $3,700/kW$_{ac}$. The gross capital cost of 10 MW of rooftop PV at current prices would be $3,700/kW x (1,000 kW/MW) x 10 MW = $37 million. The cost to construct a dedicated feeder to interconnect 10 MW of rooftop PV would be approximately 5 percent of the gross project capital cost. This is a relatively minor cost and represents no financial impediment to developing urban rooftop PV resources.

E. There Is No Security Justification for IOU's Withholding Information on Substation Capacities and Locations from Private PV Developers, and No Economic or Technical Justification for Failure to Incorporate Smart Grid Features in New and Upgraded Distribution Substations

The GSEP RSA notes that accommodating large quantities of distributed generation PV located at customer sites efficiently and cost-effectively will require the development of a new, transparent distribution planning framework (p. B.2-70). Transparent distribution planning by the IOUs is a reasonable expectation. Lack of transparent distribution planning is not a credible justification by an IOU or the CEC to reject distributed PV as a substitute for GSEP.

The CEC is already on record advocating that IOUs must incorporate smart grid elements, including bidirectional power flow, into new and upgraded distribution substations.[25] It would likely come as a surprise to most California ratepayers that it is not already standard practice for California IOUs to incorporate bidirectional power flow capability into any new distribution substation or major upgrade of an existing substation. As noted, approximately 20,000 MW of distributed PV can flow into California distribution substations without retrofitting these substations for bidirectional power flow. The lack of

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[24] Application No. 06-08-010, Matter of the Application of San DiegoGas & Electric Company (U-902-E) for a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project, *Chapter 5: Prepared Rebuttal Testimony of SDG&E in Response to Phase 2 Testimony of Powers Engineering*, March 28, 2008, p. 5.20.

[25] CEC, *2007 Integrated Energy Policy Report*, December 2007, pp. 155-156.

bidirectional power flow capability on California distribution substations is not a short- or mid-term impediment to maximizing distributed PV deployment.

However, at some point over the operational lifetime of a new or upgraded distribution substation it is prudent to assume that failure to equip the substation to accommodate bidirectional power flow will act as an artificial brake on the quantity of distributed PV the substation can accept. Equipping a distribution substation for bidirectional power flow is not expensive, costing in the range of $500,000 for a typical 100 MW distribution substation. Failure of IOUs to incorporate smart grid features as standard elements in new and upgraded distribution substations is not a credible justification by an IOU or the CEC to reject distributed PV as a substitute for GSEP.

The rationale put forth for restricting information to private distributed PV project developers includes "Providing details on distribution system could compromise homeland security" and "Information on peak loads and system configuration may be considered commercially sensitive."[26] There is no sound basis for these two justifications.

In the first instance, climate change is seen as a major threat to national security by the U.S. defense establishment.[27] Withholding information that would allow rapid progress on addressing climate change on homeland security grounds is contrary to the national security interest. Secondly, all IOU expenditures are passed on to customers. The withholding of information on peak loads and system configuration by the IOU to protect unsubstantiated commercial sensitivity concerns, to the extent it prevents the rapid deployment of competitively-bid distributed PV in urban centers at or near the point-of-use, would have a potentially substantial negative impact on ratepayers and slow progress on addressing climate change.

Much of the necessary information is already in the public domain in some form and should be compiled and made available to distributed PV developers in a transparent and

[26] E3 and Black & Veatch, *Straw proposal of solution to address short-term problem of information gap*, presentation at CPUC Re-DEC Working Group Meeting, December 9, 2009, p. 9. Online at: http://www.cpuc.ca.gov/PUC/energy/Renewables/Re-DEC.htm
[27] New York Times, *Climate Change Seen as Threat to U.S. Security*, August 9, 2009.

efficient format. For example, the CPUC already has the data on IOU substation interconnection limitations as shown in Figure 1. Another example is information on the location of IOU substations. Maps showing the location of all IOU substations are readily available for purchase from the CEC Cartography Unit.

The province of Ontario (Canada) makes publicly-available information on substation location and available capacity to facilitate the development of distributed PV in the province.[28] This same information protocol should be followed by California IOUs.

Finally, SCE must provide this type of information to third-party PV developers for the 250 MW private PV developer set-aside component of its 500 MW urban PV project approved by the CPUC in June 2009.

F. There is Sufficient Existing Large Commercial Roof Space in PG&E and SCE Territories to Build at Least Thirty GSEP Plants

The 2009 IEPR Final Committee Report recognizes the huge technical potential of rooftop distributed PV to meet California's renewable energy targets, stating:[29]

"Recent studies indicate substantial technical potential for distribution-level generation resources located at or near load. A 2007 estimate from the Energy Commission suggests that there is roof space for over 60,000 MW of PV capacity, although the study did not factor in roof space that is shaded or being used for another purpose."

60,000 MW is approximately the peak summertime load for all of California, and 250 times the 250 MW capacity of GSEP. It is important to note that the 2009 IEPR document is incorrect in asserting the 2007 rooftop PV estimate did not factor in roof shading or other limitations. The 60,000 MW estimate assumes only 24 percent of the rooftop of a typical tilt-roof residential rooftop is available for PV, and only 60 to 65 percent of flat-roof

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[28] E3 and Black & Veatch, *Straw proposal of solution to address short-term problem of information gap*, presentation at CPUC Re-DEC Working Group Meeting, December 9, 2009, p. 8.

[29] CEC, *2009 Integrated Energy Policy Report (IEPR) – Final Committee Report*, December 2009, p. 193.

commercial rooftops are available for PV. The rationale for these estimates is explained in the 2007 (Navigant) estimate.[30]

The 60,000 MW rooftop PV estimate by Navigant does not account for any of the distributed PV described in the Renewable Energy Transmission Initiative (RETI) process. RETI is California's ongoing renewable energy transmission siting process. RETI evaluated a distributed PV alternative that would produce 27,500 MWac from 20 MW increments of ground-mounted PV arrays at 1,375 non-urban substations around the state.[31] This is similar to the approach that PG&E is following. Constructing distributed PV arrays around substations is the primary focus of PG&E's 500 MW distributed PV project.[32]

Black & Veatch is the engineering contractor preparing the RETI reports. Energy & Environmental Economics, Inc. (E3) is the engineering contractor that prepared the June 2009 CPUC preliminary analysis of the cost to reach 33 percent renewable energy by 2020. These two firms now lead the CPUC's renewable distributed generation ("Re-DEC") working group process. The presentation of E3 and Black & Veatch at the December 9, 2009 initial meeting of the Re-DEC Working Group included an estimate of over 8,000 MWac of large commercial roof space in SCE and PG&E service territories in close proximity to existing distribution substations.[33]

Black & Veatch used GIS to identify large roofs in California and count available large roof area. The criteria used to select rooftops included:

- Urban areas with little available land
- Flat roofs larger than ~1/3 acre
- Assume 65 percent usable space on roof
- Within 3 miles of distribution substation

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[30] See: http://www.energy.ca.gov/2007publications/CEC-500-2007-048/CEC-500-2007-048.PDF
[31] Renewable Energy Transmission Initiative, *RETI Phase 1B Final Report*, January 2009, p. 6-25.
[32] PG&E Application A.09-02-019, *Application of Pacific Gas and Electric Company to Implement Its Photovoltaic Program*, February 24, 2009.
[33] E3 and Black & Veatch, *Summary of PV Potential Assessment in RETI and the 33% Implementation Analysis*, presentation at Re-DEC Working Group Meeting, December 9, 2009, p. 24. Online at: http://www.cpuc.ca.gov/PUC/energy/Renewables/Re-DEC.htm

The Black & Veatch estimate for PG&E territory is 2,922 MWac. The estimate for SCE territory is 5,243 MWac. This is a combined rooftop PV capacity of over 8,000 MWac. The combined large commercial rooftop capacity is more than 30 times the 250 MW capacity of GSEP.

Large commercial rooftop PV capacity is a subset of the universe of all commercial rooftop capacity, which includes medium and small commercial rooftops as well. A 2004 Navigant study prepared for the Energy Foundation estimated the 2010 commercial rooftop PV capacity in California at approximately 37,000 MWdc.[34] There is a tremendous amount of commercial roof space available for PV.

G. GSEP RSA Uses Outdated PV Cost Assumption to Erroneously Assert GSEP is Lower Cost than Equivalent Distributed PV Capacity

There is no justification for the GSEP RSA using an obsolete cost assumption to eliminate large-scale distributed PV as an alternative to the GSEP. The GSEP RSA relies on the June 2009 CPUC *33% Renewables Portfolio Standard Implementation Analysis Preliminary Results* assertion that the cost of a high distributed PV case is significantly higher than the other 33 percent RPS alternative cases (p. B2-69). The 33 percent reference case includes 10,000 MW of remote central station solar plants like GSEP. The assertion that the high distributed generation case is significantly higher cost than the reference case was incorrect in June 2009 and is definitively obsolete in April 2011.

The CPUC erroneously assumed a distributed PV cost of over $7/Wac in its June 2009 analysis.

However, the CPUC also analyzed a sensitivity case with the capital cost of fixed thin-film PV at $3.70/Wac. The CPUC determined that at $3.70/Wac, the cost of the 33 percent standard remote case and the high DG alternative are similar. RETI has confirmed that the PV pricing cited by the CPUC in its sensitivity analysis is commercially available and not a projection, stating, “Thin film solar PV was previously treated as a sensitivity study, but

[34] Navigant, *PV Grid Connected Market Potential under a Cost Breakthrough Scenario*, prepared for The Energy Foundation, September 2004, p. 83. California commercial rooftop PV potential estimated at approximately 37,000 MWp.

due to falling costs and the increased prevalence of thin film, it is now being considered as one of the available commercial technologies in addition to tracking crystalline PV."[35]

Accurate PV pricing data has been available from the SCE urban solar PV application for over three years. SCE provided an installed cost of $3.50/Wdc (~$4/Wac) in its March 2008 application to the CPUC to build a 250 MW urban PV project. RETI states that the commercially available thin-film PV has a capital cost range of $3.60 to $4/Wac, and commercially available single-axis tracking polysilicon PV has a cost range of $4 to $5/Wac.[36]

These PV costs compare to a capital cost range for solar thermal, assumed to be dry-cooled, of $5.35 to $5.55/Wac. RETI indicates the capacity factor for thin-film PV is essentially the same as for dry-cooled solar thermal (assuming the same location). The capacity factor for single-axis tracking polysilicon PV is significantly better than that of dry-cooled solar thermal (assuming the same location). Operations and maintenance cost for either fixed thin-film PV or single-axis tracking polysilicon PV is lower than for dry-cooled solar thermal. This RETI data is summarized in Table 2 below.

Table 2. RETI Capital Cost, Capacity Factor, and O&M Cost – Dry-Cooled Solar Thermal, Fixed Thin-Film PV, and Single-Axis Tracking Polysilicon PV

Solar Technology	Capital Cost ($/kWac)	Capacity Factor (%)	O&M Cost ($/MWh)
Dry-cooled solar thermal	5,350 – 5,550	20 – 28	30
Fixed thin-film PV	3,600 – 4,000	20 - 27	20 - 27
Single-axis tracking polysilicon PV	4,000 – 5,000	23 - 31	17 - 25

The GSEP RSA comment on the capacity factors of solar thermal and rooftop PV is out-of-date (p. B.2-67): "The Renewable Energy Transmission Initiative (RETI) assumed a

[35] RETI, *Phase 2B Final Report*, May 2010, p. 4-6.
[36] Ibid, Tables 4-5, 4-7, 4-8, pp. 4-6 and 4-7.

capacity factor of approximately 30 percent for solar thermal technologies and tracking solar PV and

approximately 20 percent capacity factor for rooftop solar PV which is assumed to be non-tracking, for viable solar generation project locations (B&V 2008; CEC 2009)." As shown in Table 2, the RETI capacity factors of solar thermal and fixed (rooftop) solar PV are essentially the same assuming the same location.

The effect of the values in Table 2 on the levelized cost-of-energy (COE) for dry-cooled solar thermal, fixed thin-film PV, and single-axis tracking polysilicon PV is shown in Table 3.[37] The average levelized COE for either fixed thin-film PV or single-axis tracking polysilicon PV is significantly lower than the levelized COE of dry-cooled solar thermal plants.

Table 3. RETI Cost-of-Energy (COE) Comparison - Dry-Cooled Solar Thermal, Fixed Thin-Film PV, and Single-Axis Tracking Polysilicon PV

Solar Technology	Levelized COE ($/MWh)
Dry-cooled solar thermal	$195 – 226 (mean: $210)
Fixed thin-film PV	$135 – 214 (mean: $175)
Single-axis tracking polysilicon PV	$138 – 206 (mean: $172)

The CPUC determined that there would be little difference in the cost of meeting state renewable energy targets by relying predominantly on distributed PV, when current state-of-the-art pricing is assumed, instead of building 10,000 MW of remote solar capacity under the 33 percent RPS reference case.[38] This conclusion was reached despite a number of controversial cost assumptions by the CPUC that favored the 33 percent RPS reference case.[39] An additional controversial assumption is the low assumed cost of new transmission to realize the 33 percent reference case. The CPUC assumed the total cost of new

[37] Ibid, Figure 4-1, p. 4-8.
[38] CPUC, *33% Renewables Portfolio Standard Implementation Analysis Preliminary Results*, June 2009, p. 31.
[39] RightCycle Inc. comment letter, working group member response to June 2009 *33% Renewables Portfolio Standard Implementation Analysis Preliminary Results*, in response to CPUC request for comments, August 28, 2009.

transmission would be $12 billion. The current estimate is over $27 billion.[40] When current projections regarding the cost of new transmission and associated upgrades are used, the high distributed generation alternative is more cost-effective than the 33 percent reference case.

The RETI capital cost values for PV assume 20 MW systems located at distribution substations. However, even the cost of individual commercial rooftop PV installations is now lower than the RETI cost of $5.35 to $5.55/Wac for dry-cooled solar thermal plants.

The May 2010 DOE Solar Vision Study (draft) projection of current commercial rooftop PV capital cost is provided in Figure 3.[41] These capital cost values are provided in Wdc. As shown in Figure 2, the current capital cost of commercial rooftop polysilicon PV (multi Si and mono Si) is approximately $4/Wdc. RETI identifies the range of dc-to-ac conversion factors of 0.77 to 0.85.[42] Using an average dc-to-ac conversion factor of 0.80, the capital cost of commercial rooftop polysilicon PV is approximately $4/Wdc ÷ 0.80 = $5/Wac. This is incrementally less than the $5.35 to $5.55/Wac capital cost of dry-cooled solar thermal, and the commercial rooftop PV array could be as little as 1/1,000th the size of the solar thermal plant. The most common form of thin-film PV, CdTe (cadmium-telluride), is lower in cost than polysilicon PV at approximately $3.60/Wdc. This converts to $3.60/Wdc ÷ 0.80 = $4.50/Wac.

Figure 2. Cost of Commercial Rooftop PV Identified by DOE

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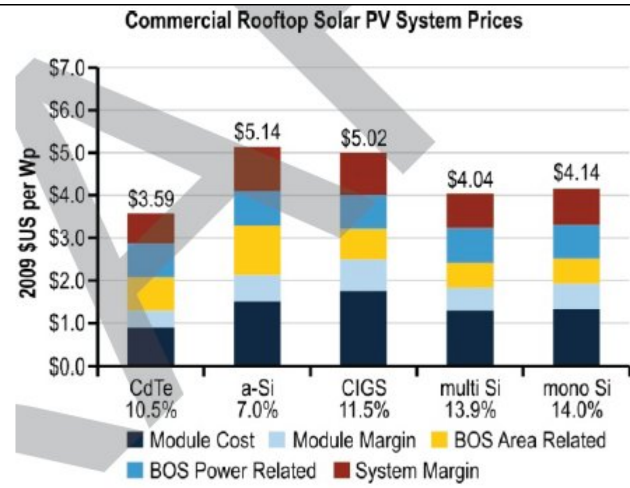
[40] J. Firooz, P.E., CAISO: *How Its Transmission Planning Process has Lost Sight of the Public's Interest*, April 2010, Table 2, p. 10. Total new transmission and upgrades necessary to realize 33 percent RPS reference case as of September 2009 - $27.544 billion.
[41] DOE, *DOE Solar Vision Study – DRAFT*, May 28, 2010, Chapter 4, Figure 4-4, p. 7.
[42] RETI, *Phase 1A Final Report*, August 2008, Appendix B, p. 5-5.



a-Si: amorphous silicon thin-film PV; CIGS: copper-indium-gallium-selenide thin-film PV.

H. Market Price Referent with Adjustment for Time-of-Delivery would be Sufficient Price to Assure Rapid Construction of 250 MW Distributed PV Alternative to GSEP

The CPUC has established that the levelized cost-of-energy (LCOE) from a new natural gas-fired combined cycle unit is the representative market price of electricity that renewable energy resource costs are compared to in the California RPS program. This representative LCOE is called the "Market Price Referent - MPR."[43] The MPR consists of the LCOE for a new combined cycle plant plus an adder of $15 per ton of CO_2 emissions.[44] The concept behind the MPR is that ratepayers should be protected from excessive green energy costs by requiring that renewable energy resources be no more costly than the conventional brown power they will replace.

Combined cycle units operate as intermediate-load plants in California. They typically operate at capacity factors of 60 to 70 percent.[45] The fleet average capacity factor in 2008 was 65 percent.[46,47] "Capacity factor" is a measure of actual annual electricity production

[43] MPR is the cost-of-energy for a new natural gas-fired combined cycle that includes a greenhouse gas emissions adder. See CPUC MPR website: http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr
[44] CPUC MPR webpage, 2009 MPR Documents, 2009 MPR Model, Appendix F – Non-Gas Inputs: http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr
[45] William Marcus, JBS Energy, Inc. on behalf of TURN, *MPR Capacity Factor*, PowerPoint presentation given at CPUC MPR workshop, R.06-02-012, March 27, 2008.
[46] CEC, *Comparative Costs of California Central Station Electricity Generation,* January 2010, p. C-12. Table C-5: Combined Cycle Facility Capacity Factors. Average capacity factor for 15 California combined cycle plants in 2008 is 65 percent.
[47] CPUC assumes 65% capacity factor for combined cycle units in *Inputs and Assumptions to 33% Renewables Portfolio Standard Implementation Analysis,* prepared by E3 for CPUC, July 2009.

compared to maximum possible output if the unit is operated every hour of the year at maximum output. Combined cycle units generally do not operate during off-peak, low demand periods. Low demand periods include midnight to 6 am most workdays as well as weekends. Lower-cost nuclear, large hydroelectric, and coal plants are available to meet the need during these periods. Combined cycle units are not the high-cost generation resource during summer peak periods, as simple cycle peaking turbines and older conventional steam plants with higher operating costs are online.

A representative avoided cost for a solar PV system in PG&E service territory can be calculated using: 1) the MPR, adjusted to reflect a typical 65 percent capacity factor for a combined cycle plant and adjusted for the TOD of solar generation, and 2) the line losses and transmission and distribution (T&D) costs that are avoided by the typical solar PV system.

The CPUC and the CEC have both developed estimates of the LCOE for a new 500 MW combined cycle plant. The CPUC derived its combined cycle installed cost estimate by looking at three projects that were either operational (Palomar, Consumnes) or under construction (Colusa) at the time 2009 MPR was developed.[48] The dates of the installed cost estimates for these projects are: Palomar –June 2004, Consumnes – January 2006, and Colusa – February 2008. The 2009 MPR calculation assumes a January 2010 online date.

In contrast, the CEC used a non-project specific combined cycle pricing model to develop LCOE projections for 2009 and 2018 online dates.[49] The CEC also examines a range of capacity factors. LCOE projections were developed for capacity factors of 55 percent, 75 percent, and 90 percent for an unfired 500 MW combined cycle unit. LCOE projections were also developed for capacity factors of 50 percent, 70 percent, and 85 percent for a duct-fired 550 MW combined cycle unit.[50]

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[48] CPUC MPR webpage, 2009 MPR Documents, 2009 MPR Model, "Install_Cap" tab: http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr.
[49] CEC, *Comparative Costs of California Central Station Electricity Generation* , January 2010, Appendix B.
[50] Ibid, Tables 11 - 13.

The CPUC currently assumes a hypothetical capacity factor of 92 percent for a combined cycle unit when calculating the MPR.[51] However, the CPUC uses a capacity factor of 65 percent when calculating the actual expected electricity production from California's fleet of combined cycle plants.[52] The effect of using the unrealistically high capacity factor of 92 percent in the MPR calculation is to make the MPR reference price artificially low. The effect of capacity factor on the LCOE for a new 500 MW combined cycle plant is shown in Table 4 using the CEC combined cycle LCOE estimates.[53]

Use of a MPR based on a 65 percent capacity factor would accurately reflect typical usage rates of operating combined cycle plants in California. This value is $134/MWh for an online date of 2009, and is projected by the CEC to rise to $183/MWh for an online date of 2018. Powers Engineering has taken the mid-point between these two values to estimate the MPR for an online date in the 2013 to 2014 timeframe. This MPR value is $158/MWh.

Four new gas-fired power plants have PPAs and are planned for construction over the next few years in Northern California alone. The proposed start dates for 600 MW Russell City, 624 MW Oakley, 760 MW Marsh Landing, and 200 MW Mariposa are 2013, 2016, 2013, and 2012 respectively.[54] Given the average start-up date for this gas-fired capacity that could be substituted with DG is 2013 to 2014, the appropriate MPR value is for a combined cycle unit that will be online in 2013 or 2014. This is an MPR of $158/MWh.

Table 4. Effect of Capacity Factor on LCOE from New Combined Cycle Plant

Capacity factor (%)	LCOE, 2009 ($/MWh)	LCOE, 2013/2014 ($/MWh)	LCOE, 2018 ($/MWh)
92	118	140	161
75	124	147	169

[51] CPUC MPR webpage, 2009 MPR Documents, 2009 MPR Model: http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr.
[52] CPUC assumes 65 percent capacity factor for combined cycle units in *Inputs and Assumptions to 33% Renewables Portfolio Standard Implementation Analysis,* prepared by E3 for CPUC, July 2009.
[53] CEC, *Comparative Costs of California Central Station Electricity Generation ,* January 2010, Table 1, Table 5, Figure A-8. A 500 MW unfired merchant combined cycle plant with a 75 percent capacity factor is the average case in the CEC report. Note – the dates shown in the table, 2009 and 2018, are commercial start dates.
[54] CPUC Application A.09-09-021, Application by PG&E for Approval of 2008 Long-Term Request for Offers Results, *Alternate Proposed Decision of Commissioner Bohn*, November 2, 2010.

65	134	158	183
55	146	173	199

Note: CEC provides LCOE values for online dates of 2009 and 2018. The values included for 2013/2014 were calculated by Powers Engineering and are the average of the 2009 and 2018 values.

SCE applies a TOU factor for PV of 1.32.[55] The adjusted MPR for PV, which includes the time-of-delivery value of PV, is 1.32 x $158/MWh = $209/MWh ($0.209/kWh).

The T&D system is designed to meet peak demand loads. The addition of distributed generation of any kind that reduced demand on the T&D system under peak conditions either delays or eliminates the need for existing substation upgrades or new T&D infrastructure. Energy and Environmental Economics, Inc. (E3), a CPUC contractor, developed the model adopted by the CPUC to determine the T&D avoided costs associated with energy efficiency programs.[56] The approximate weighted average (population based) T&D benefit of energy efficiency programs in PG&E territory is about $20/MWh.[57]

California Solar Initiative fixed PV systems in PG&E service territory have a demonstrated availability during the 4-5 pm peak hour of summer demand of more than 50 percent.[58] The peak availability of fixed PV is conservatively assumed to be 50 percent in this cost calculation. The full avoided T&D value of $20/MWh must be multiplied by 0.50 to accurately reflect the avoided T&D value of fixed PV. This means that the solar PV T&D avoided cost would be $10/MWh, or $0.10/kWh.

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[55] CPUC A.10-03-012, Application of PG&E to Implement Assembly Bill 920 (2009) Setting Terms and Conditions for Compensation for Excess Energy Deliveries by Net Metered Customers*, Proposal of the Solar Alliance and Vote Solar Initiative for a Net Surplus Compensation Rate and Responses to Scoping Memo Questions*, June 21, 2010, Table 2, p. 4.
[56] CPUC R.06-02-12, Rulemaking to Develop Additional Methods to Implement the California Renewables Portfolio Standard Program, *Pre-Workshop Comments of GreenVolts, Cleantech America, and Community Environmental Council on the 2008 Market Price Referent*, March 6, 2008, p.15. Table - E3 Model T&D Values (Levelized 20-year in 2008$).
[57] Ibid.
[58] Itron, *CPUC Self-Generation Incentive Program—Ninth-Year Impact Evaluation Report – Final Report,* submitted to PG&E, June 2010, Table 5-14, p. 5-32. PG&E peak hour fixed PV capacity factor in 2009 was 54 percent, July 14, 2009, 4-5 pm.

An MPR-adjusted price of $0.209/kWh, plus an average transmission & distribution benefit of approximately $0.010/kWh, is equivalent to an overall value to the IOU of approximately $0.22/kWh. Any price paid for distributed PV by an IOU below this price threshold should result in a net benefit to all of the IOU's ratepayers. A distributed PV price in the range $0.22/kWh would be more than sufficient to create a dynamic market for third party development of large-scale distributed PV in California urban areas.

I. Rooftop Commercial PV is More Space Efficient than GSEP and has None of the Environmental Impacts of GSEP

The GSEP RSA states, without citation: "However, based on SCE's use of 600,000-square-feet for 2 MW(ac) of energy, 75 million square feet (approximately 1,750 acres) would be required for 250 MW" (p. B2-67). SCE states in its March 2008 solar PV program testimony that 125,000 square feet of polysilicon panels are required to generate 1 MWdc.[59] This converts to about 150,000 square feet per MWac, or approximately 3.5 acres per MWac.[60] This is one-half the square-footage per MWac that the GSEP RSA erroneously attributes to SCE rooftop installations. SCE has signed contracts with SunPower and Trina Solar, both suppliers of polysilicon PV panels, to provide a combined total of 245 MW of the 250 MW of PV capacity that will be owned by SCE.[61,62]

Rooftop PV is also approximately twice as space efficient as the GSEP project. The GSEP RSA states that 1,800 acres will be developed to produce 250 MWac (p. B1-2). This is more than 7 acres per MWac.

The predominant advantage of rooftop (or parking lot) PV is that it represents a compatible dual use of existing developed structures with no environmental impacts. As the GSEP RSA correctly notes, "Distributed solar PV is assumed to be located on already existing structures or disturbed areas so little to no new ground disturbance would be required and there would be few associated biological impacts" (p. B.2-68).

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[59] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Testimony*, March 27, 2008, p. 32.

[60] There are 43,560 square feet per acre. Therefore, 150,000 square feet per MWac ÷ 43,560 square feet per acre = 3.44 acre/MWac.

[61] SNL Financial, *SoCalEd orders 200 MW of solar panels, plans solicitation for 250 MW more*, March 10, 2010.

[62] SNL Financial, *SoCalEd taps Trina Solar to supply 45 MW of PV modules*, June 9, 2010.

J. GSEP RSA Concerns about Sufficient PV Panel Manufacturing Capacity Are Baseless

The concerns expressed in the GSEP RSA regarding the availability of distributed solar PV are without foundation. The GSEP RSA states (p. B.2-70): "While it will very likely be possible to achieve 250 MW of distributed solar energy over the coming years, the very limited number of existing facilities make it difficult to conclude with confidence that it will happen within the timeframe required for the GSEP. As a result, this technology is eliminated from detailed analysis in this GSEP RSA." Over 21,000 MW of PV systems, most of them distributed PV systems, were operational worldwide by the end of 2009.[63] More than 7,000 MW of PV was installed worldwide in 2009 alone.[64] In contrast, only 127 MW of solar thermal plants were constructed in 2009.[65]

Thin-film PV manufacturing capacity is projected to reach 7,400 MW per year in 2010.[66] First Solar alone manufactured and shipped more than 1,000 MW of thin-film panels in 2009.[67]

Worldwide conventional polysilicon PV production capacity reached 13,300 MW a year in 2008.[68] It is projected to reach 20,000 MW a year in 2010. The 2010 projections were made just as the economic slump began in late 2008. It is likely there will be some scale-back on the 2010 capacity additions due to the state of the world economy. Nonetheless, there is a tremendous amount of available worldwide PV manufacturing capacity.

PV panel manufacturing capacity has greatly expanded worldwide in the last 2 to 3 years. The current estimated oversupply of PV panel manufacturing capacity for 2010 is 8,000

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[63] Worldwatch Institute, *Record Growth in Photovoltaic Capacity and Momentum Builds for Concentrating Solar Power*, June 3, 2010.
[64] Ibid.
[65] Ibid.
[66] Schreiber, D. - EuPD Research, *PV Thin-film Markets, Manufacturers, Margins*, presentation at 1st Thin-Film Summit, San Francisco, December 1-2, 2008.
[67] First Solar press release, *First Solar Becomes First PV Company to Produce 1GW in a Single Year*, December 15, 2009.
[68] Schreiber, D. - EuPD Research, *PV Thin-film Markets, Manufacturers, Margins*, presentation at 1st Thin-Film Summit, San Francisco, December 1-2, 2008.

MW.[69] As a result of this oversupply, the cost of conventional polysilicon PV panels has dropped precipitously and is approaching the cost of thin-film PV panels (see Figure 3).

The GSEP RSA states that California added 158 MW of distributed PV in 2008 (p. B.2-66). California is a relatively minor player on the world PV stage. Spain added approximately 2,500 MW of primarily distributed ground-mounted PV resources in 2008.[70] Spain has a smaller economy than California. Germany, approximately the same size as California and with considerably lower solar intensity, added approximately 1,500 MW of distributed PV resources in 2008 and 3,800 MW in 2009.[71,72] Germany had an installed PV capacity of nearly 9,000 MW at the end of 2009 and has set a target PV installation rate of 3,500 MW per year.[73]

The GSEP RSA expresses concerns regarding the feasibility of California doubling its 158 MW per year (2008) distributed PV installation rate as a substitute for GSEP, stating (p. B.2-69): "This would require an even more aggressive deployment of PV at more than double the historic rate of solar PV implementation than the California Solar Initiative program currently employs." This doubling of distributed PV deployment is equivalent to going from 1/20th to 1/10th the current German distributed PV installation rate. The feasibility concern expressed in the RSA is unfounded in light of German success with a high rate of distributed PV deployment.

The high distributed PV alternative studied by the CPUC anticipates the installation of 15,000 MW of distributed PV by 2020.[74] RETI has gradually dropped the amount of new renewable energy resources needed to reach 33 percent by 2020, the "net short," from 74,650 gigawatt-hours (GWh) per year initially to a current "low load" net short of 36,926

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[69] B. Murphy – Fulcrum Technologies, Inc., *The Power and Potential of CdTe (thin-film) PV*, presented at 2nd Thin-Film Summit, San Francisco, December 1-2, 2009.
[70] PV Tech, *Worldwide photovoltaics installations grew 110% in 2008, says Solarbuzz*, March 16, 2009.
[71] PV Tech, *German market booming: Inverter and module supplies running out at Phoenix Solar*, November 15, 2009.
[72] Worldwatch Institute, *Record Growth in Photovoltaic Capacity and Momentum Builds for Concentrating Solar Power*, June 3, 2010.
[73] Chadbourne & Parke Project Finance Newswire, *Germany Cuts Solar Subsidy*, April 2010.
[74] CPUC, *33% Renewables Portfolio Standard Implementation Analysis Preliminary Results*, June 2009.

MW.[75] The low load net short is one-half the net short used by the CPUC in June 2009 to estimate the cost of achieving 33 percent by 2020. 15,000 MW of distributed PV would provide about 30,000 GWh/yr.[76] 15,000 MW of distributed PV would provide over 80 percent of the low load net short of 36,926 MW.

California could easily install 15,000 MW of distributed PV by 2020 if it approached the annual distributed PV installation rates that have already been achieved in practice in Spain and Germany. Existing worldwide PV manufacturing capacity, either thin-film alone or thin-film and conventional polysilicon, could readily supply a PV demand of 1,500 to 2,500 MW a year in California.

K. Slight Reduction in Output from Distributed PV in Los Angeles, Central Valley, or Bay Area Is Offset by Transmission Losses from GSEP to These Load Centers

The GSEP RSA implies that the superior solar intensity at the GSEP location in the Mojave Desert is a substantive reason for eliminating distributed PV from consideration, stating (p. B.2-67):

"The location of the distributed solar PV would impact the capacity factor of the distributed solar PV. Capacity factor depends on a number of factors including the insolation of the site. Because a distributed solar PV alternative would be located throughout the state of California, the insolation at some of these locations may be less than in the Mojave Desert."

The solar insolation at the GSEP site is about 10 to 15 percent better than the composite solar insolation for Los Angeles, the Central Valley, and Oakland.[77,78] However, the CEC

[75] RETI discussion draft, *RETI Net Short Update - Evaluating the Need for Expanded Electric Transmission Capacity for Renewable Energy*, February 22, 2010. Low load scenario, net short = 36,926 MW.
[76] The CPUC reference case assumes 3,235 MW of solar PV will generate 6,913 GWh per year under ideal Southern California desert solar insolation conditions. This is a production ratio of 2,137 GWh per MWac. However, solar insolation in the Central Valley and California urban areas will on average be approximately 10 less than ideal desert sites. For this reason a production ratio of 2,000 GWh per year per MWac is assumed for the Central Valley and urban areas.
[77] U.S. DOE, *Stand-Alone Flat-plate Photovoltaic Systems: System Sizing and Life-Cycle Costing Methodology for Federal Agencies*, 1984, Appendix, p. A-27.
[78] NREL, *Solar Radiation Data Manual for Flat-Plate and Concentrating Collectors*, California cities data: http://rredc.nrel.gov/solar/pubs/redbook/PDFs/CA.PDF

estimates average transmission losses in California at 7.5 percent and peak transmission losses at 14 percent.[79] The incrementally better solar insolation at the GSEP site is almost completely negated by the losses incurred by transmitting GSEP solar power to California urban areas. In contrast, distributed PV has minimal losses between generation and user.

L. CEC Has Already Determined Distributed PV Can Compete Cost-Effectively with Other Forms of Generation

The CEC denied an application for a 100-megawatt natural-gas-fired gas turbine power plant, the Chula Vista Energy Upgrade Project (CVEUP), in June 2009 in part because rooftop solar PV could potentially achieve the same objectives for comparable cost.[80]

This June 2009 CEC decision implies that any future applications for gas-fired generation in California, or any other type of generation including remote central station renewable energy generation like GSEP that require public land and new transmission to reach demand centers, should be measured against using urban PV to meet the power need. The CEC's final decision in the CVEUP case stated:[81]

"Photovoltaic arrays mounted on existing flat warehouse roofs or on top of vehicle shelters in parking lots do not consume any acreage. The warehouses and parking lots continue to perform those functions with the PV in place. (Ex. 616, p. 11.)….Mr. Powers (expert for intervenor) provided detailed analysis of the costs of such PV, concluding that there was little or no difference between the cost of energy provided by a project such as the CVEUP (gas turbine peaking plant) compared with the cost of energy provided by PV. (Ex. 616, pp. 13 – 14.)….PV does provide power at a time when demand is likely to be high—on hot, sunny days. Mr. Powers acknowledged on cross-examination that the solar peak does not match the demand peak, but testified that storage technologies exist which could be used to manage this. The essential points in Mr. Powers' testimony about the costs and practicality of PV were uncontroverted."

[79] E-mail communication between Don Kondoleon, manager - CEC Transmission Evaluation Program, and Bill Powers of Powers Engineering, January 30, 2008.
[80] CEC, Chula Vista Energy Upgrade Project - Application for Certification (07-AFC-4) San Diego County, *Final Commission Decision*, June 2009.
[81] Ibid, pp. 29-30.

The CEC concluded in the CVEUP final decision that PV arrays on rooftops and over parking lots may be a viable alternative to the gas turbine project proposed in that case, and that if the gas turbine project proponent opted to file a new application a much more detailed analysis of the PV alternative would be required.

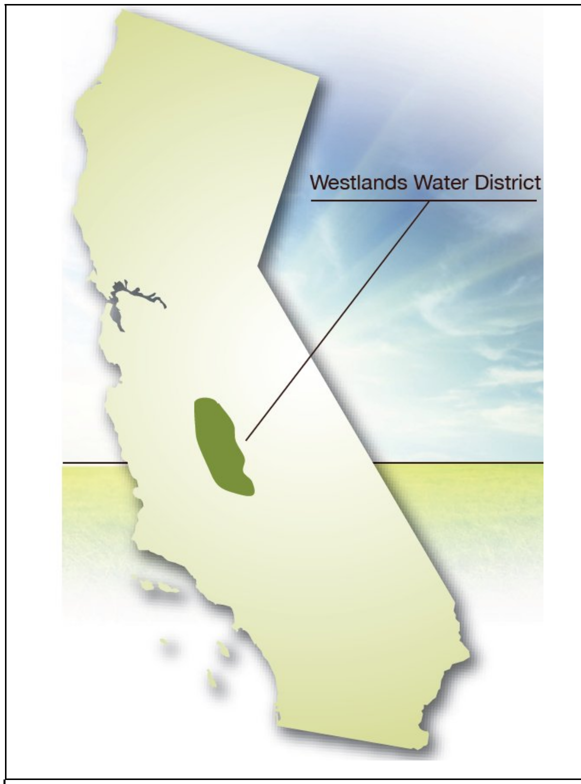
IV. Locating GSEP in the Proposed Westlands Water District CREZ would Avoid Environmental Impacts at the GSEP Site

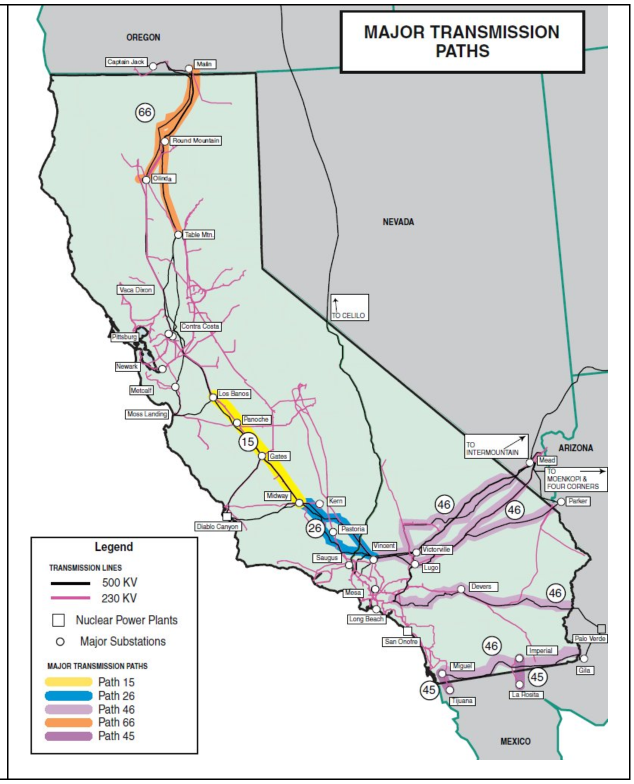
The Westlands Water District ("Westlands"), on the west side of the Central Valley, is undergoing study by RETI as a Competitive Renewable Energy Zone (CREZ) capable of providing 5,000 MW of utility-scale solar development. Westlands covers over 600,000 acres of farmland in western Fresno and Kings Counties. The proposed "Central California Renewable Master Plan" will utilize permanently retired farmlands in Westlands for solar development. An overview of this master plan is attached. As stated in the master plan overview, "Due to salinity contamination issues, a portion of this disturbed land has been set aside for retirement and will be taken out of production under an agreement between Westlands and the U.S. Department of Interior." Approximately 30,000 acres of disturbed Westlands land, equivalent to 5,000 MW of solar capacity, will be allocated for renewable energy development under the plan.

Transmission Pathway 15 passes through Westlands. Path 15 can transmit 5,400 MW from south-to-north.[82] The transmission capacity from north-to-south is 3,400 MW. The location of Westlands relative to Path 15 is shown in Figure 3.

Figure 3. Location of Westlands Water District and Path 15[83,84]

[82] Transmission & Distribution World, California bulks up to provide more transmission capacity, June 1, 2004.
[83] Anthem Group press release, Central California Renewable Master Plan, March 2010.
[84] CEC, *Strategic Transmission Investment Plan*, November 2005, p. 11.





5,000 MW of solar power can be developed in Westlands with potentially no expansion of the existing Path 15 high voltage transmission capacity that serves Westlands now.

5,000 MW is half of the total remote in-state utility-scale solar contemplated in the June 2009 CPUC 33 percent reference case.[85] The remote in-state solar component of the reference case consists of 3,235 MW central station PV and 6,764 MW central station solar thermal. The anticipated energy output of 5,000 MW of fixed PV in Westlands would be about 10,000 GWh/yr.[86] This is approximately 30 percent of the RETI low load net short of 36,926 MW.

The GSEP RSA states that the Gabrych disturbed lands alternative near the GSEP site does not meet project objectives due to the inability to assure site control of multiple private parcels by the end of 2010 (p. B.2-53). Site control would not be an issue in the proposed

[85] CPUC, *33% RPS Implementation Analysis Preliminary Results*, June 2009, Appendix C, p. 87.
[86] The CPUC reference case assumes 3,235 MW of solar PV will generate 6,913 GWh per year under ideal Southern California desert solar insolation conditions. This is a production ratio of 2,137 GWh per MWac. However, solar insolation in the Central Valley and California urban areas will on average be approximately 10 less than ideal desert sites. For this reason a production ratio of 2,000 GWh per year per MWac is assumed for the Central Valley and urban areas.

Westlands CREZ. Westlands is actively marketing the 30,000-acre area for development of central station solar power plants. Development of solar projects on the Westlands property is intended (by Westlands) to serve as a source of income on land that has been permanently retired from agricultural production.

Prioritizing distributed PV projects, combined with the location of central station solar projects in Westlands, would allow California to achieve its 33 percent by 2020 renewable energy target with almost no environmental impacts related to the solar energy component of the renewable energy portfolio.

V. Conclusions

The DPV2 Draft Supplemental EIR is inadequate for failure to conduct an analysis of non-transmission alternatives to the DPV2. In contrast, the Draft and October 2008 Final EIR/EIS prepared by the CPUC and BLM for SDG&E's proposed Sunrise Powerlink transmission line includes voluminous analysis of multiple non-transmission alternatives to the proposed project. The CPUC/BLM Final EIR/EIS for the Sunrise Powerlink concluded that either of the two non-transmission in-basin alternatives studied were environmentally superior to the proposed project or any transmission alternative to the proposed project. The DPV2 Draft Supplemental EIR avoids a similar conclusion by failing to analyze in detail any non-transmission alternative to the DPV2.

This comment letter uses comments provided by Powers Engineering on alternatives to GSEP as a case study to show that non-transmission alternatives are more cost-effective than the solar thermal projects that DPV2 is being built to serve. The GSEP RSA analysis of the distributed PV alternative to GSEP used flawed logic and outdated data to improperly eliminate distributed PV as an alternative. The DPV2 Draft Supplemental EIR contains no analysis of any kind. Distributed PV is a fully viable and cost-effective alternative that eliminates the environmental impacts that would be caused by the DPV2 transmission line and the associated GSEP and BSPP solar projects.

Beyond the issue of distributed PV being a superior alternative to GSEP + BSPP + DPV2 on cost and environmental grounds, there are lower-impact sites in California for central station solar projects like GSEP and BSPP. The Westlands Water District is a low impact "shovel ready" alternative to the GSEP and BSPP sites for central station solar projects. Westlands requires no new high voltage transmission to move up to 5,000 MW of solar power to California load centers.

This means solar projects located in Westlands will not face project delays due to lack of high voltage transmission capacity. The steadily declining renewable energy net short to achieve the 33 percent by 2020 target, now as low as 36,926 MW, means fewer renewable projects overall are necessary to meet the 33 percent target. The CPUC should not approve transmission projects like DPV2 serving high-cost solar thermal projects with unmitigatable impacts, when 5,000 MW of otherwise unusable disturbed land with no environmental issues and 5,000 MW of high voltage transmission capacity sits idle.

CALIFORNIANS FOR RENEWABLE ENERGY'S INITIAL COMMENTS ON SUPPLEMENTAL DRAFT ENVIRONMENTAL IMPACT REPORT FOR COLORADO RIVER SUBSTATION EXPANSION

(California SCH 2005101104)

Exhibit 2

ON BEHALF OF CALIFORNIANS FOR RENEWABLE ENERGY COMMENTS OF ROBERT M. SARVEY ON DEVERS TO PALO VERDE 2 TRANSMISSION LINE DRAFT SUPPLEMENTAL EIR

April 8, 2011

Robert M. Sarvey
501 W. Grantline Rd
Tracy, Ca. 95375
Phone: (209) 835-7162
E-mail:
sarveybob@aol.com

Alternatives

Section 15126.2(d) of the CEQA Guidelines requires that an EIR discuss the ways in which a proposed project may foster economic or population growth, or the construction of additional housing, either directly or indirectly, in the surrounding environment. The discussion must additionally address how a proposed project may remove obstacles to growth, or encourage and facilitate other activities that could significantly affect the environment, either individually or cumulatively.

The Proposed Project would facilitate growth indirectly by removing obstacles to population growth through the additional increased capacity of electric power that it would make available. As discussed in Sections A.1.1 (Project Background) and A.1.3 (Project Objectives), the DPV2 Project, including the CRS expansion, would bring energy resources to Los Angeles from Riverside County by providing access to remote areas with the potential for significant development of renewable energy sources.

CPUC Decision D.09-11.007, which modifies D.07-01-040, concludes that SCE's revised stated objective of constructing the California portion of DPV2, including the Midpoint Substation would be to provide transmission access to potential future renewable resources in the Blythe area and help enable California to meet its renewable energy goals. Additionally, SCE has stated that an additional objective of the CRS would be to complete substation construction in a timely fashion to allow interconnection with the Blythe Solar Power Project (BSPP) and Genesis Solar Energy Project (GSEP) by the Large Generator Interconnection Agreements (LGIA) target dates.

The CAISO's interconnection queue lists generation facilities that would like access to California's transmission system. There are currently thousands of megawatts of wind and solar facilities in eastern Riverside County listed in the queue, and there is not adequate transmission capacity for these projects to be constructed. While the development of renewable energy sources has the benefit of reducing the use of older and more polluting conventional generation facilities, the renewable facilities could not be constructed without adequate transmission and a substation access point to the grid. So while the CRS may not induce urban growth, it would encourage the development of renewable projects in the Blythe area. The CRS expansion would not be needed without the construction of solar generation in the Blythe area.

Biological Resources

Implementation of the CRS expansion would additionally require the permanent loss of approximately 54.1 acres of vegetation and habitat, which equals 61.6 percent of the total land (87.8 acres) disturbed for construction. Direct and indirect loss of sand dune habitat within an active sand transport corridor would result in a significant and unmitigable direct impacts to the Mojave fringe toed lizard.[1] There are also cumulative impacts from the project in combination of other projects which the expansion of the CRS enables. These include consideration of the magnitude of threats to MFTL from existing and reasonably foreseeable future projects, the substantial habitat loss and downwind habitat degradation/elimination from the CRS project, which would ultimately result in range contraction of the species, would be cumulatively considerable. New Mitigation Measure B-9j (Provide compensatory mitigation and restoration/enhancement of protected land for impacts to sand dune habitat) would reduce the Proposed Project's contribution to cumulative MFTL habitat loss by securing and preserving unprotected private lands or enhancing/sand dunes already conserved or on BLM land that is not slated for development. Even with the implementation of mitigation, when combined with impacts of past, present, and reasonably foreseeable projects, the Proposed Project's contribution to significant cumulative MFTL impacts remains cumulatively considerable (Class I). Several of these projects are only feasible with the expansion of the CRS and therefore the EIR should discus the indirect impacts of the CRS expansion.

[1] DEIR Page G-3 http://www.cpuc.ca.gov/Environment/info/aspen/dpv2/sdeir/g_otherceqa.pdf

While the DEIR has concluded that the contribution of the CRS expansion to impacts to the Desert kit Fox, Swainson hawk, and other sensitive species is not cumulatively considerable the DEIR does not consider that the CRS expansion enables a cumulatively considerable impact form the other projects that are infeasible without the expansion to the CRS. These impacts must be examined in the final EIR.

Air Quality

From the discussion at the prehearing conference it appears that an accelerated construction schedule is being considered to allow two large solar projects to meet online dates.

"So NextEra has been attempting to work with SCE and SCE has been also working with NextEra to find ways to accelerate the construction schedule. But in order to do that, it is really important that there be a final decision in this proceeding approving a project, and approving one that is feasible and that can be built on a time frame in order to allow the Genesis project to come online.[2]"

The impacts of an accelerated construction schedule are not reflected in the DEIR. As the DEIR states, "Pollutant emissions would vary from day to day depending on the **level of activity**, the specific operations, and the prevailing weather.[3] Impacts to air quality could include increased hourly, daily, and annual construction emissions. The Final EIR must quantify and discuss these impacts. The current discussion in the DEIR is incomplete without this additional analysis as an accelerated construction schedule.

The DEIR already concludes that, "daily emissions from the Proposed Project would cause significant and unavoidable impacts in the SCAQMD (Class I)." Despite this conclusion the DEIR does not require all feasible and cost effective mitigation measures which can reduce the significant impact. Limiting construction vehicle speeds, use of electric powered equipment, and many other mitigation measures should be considered to reduce the identified significant impact. .

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[2] Prehearing conference transcript Page 46

[3] DEIR Page D.11-37

The draft DEIR also concludes that Tower construction would have the potential to cause significant localized PM10 emission impacts for sensitive receptors located near the tower sites. The significant impacts, based on the SCAQMD LST lookup table, would extend to sensitive receptors within and just over 50 meters of the tower sites. Fugitive dust mitigation measures are assumed to be implemented in these emission estimates; therefore, the Proposed Project would cause significant and unavoidable (Class I) localized PM10 impacts for nearby sensitive receptors within SCAQMD jurisdiction, and all feasible fugitive dust mitigation measures need to be applied within this jurisdiction.[4]

According to the DEIR the Proposed Project would exceed the federal General Conformity *de minimis* thresholds, **assuming the current project schedule** and activity forecasts. Table D-11.19 shows that the Proposed Project would exceed the SCAB NOx threshold for General Conformity in 2008. NOx offsets are proposed for this significant impact. As mentioned above an accelerated construction schedule is reasonably foreseeable and the impact of increased construction activity must be quantified and mitigated.[5] The DEIR contains no analysis of the localized PM-10 and NO_2 air quality impacts. With or without an accelerated construction schedule the projects construction activities could lead to localized violations of the Federal 24 hour PM 2.5 standard, the Federal 1-Hour NO_2 standard and other federal and state air quality standards established to protect the health of the nearby sensitive receptors. A complete analysis including compliance with state and federal air quality standards is required and the possible environmental justice considerations must be included in the final EIR.

The alternative route proposal fails to discuss whether sensitive receptors are located near the projects' construction areas so the DEIR fails to inform the decision makers and the public as to possible localized air quality impacts to sensitive receptors for the alternative routes. The Final EIR must include an analysis and discussion of these impacts and their environmental justice implications in order to inform the public and meet the requirements of an EIR under CEQA.

[4] DEIR Page D. 11-45
[5] DEIR Page D.11-46

The DEIR includes a discussion of a net decrease in emissions from power plants in California and a smaller increase in emissions from power plants in Arizona (described in Impact AQ-3) would not occur with implementation of No Project Alternative (CAISO, 2005). That discussion is irrelevant to the impacts of the expanded CRS. First the current proposal is to build only the California portion of the DVP2 so a realized reduction in California power plant emissions and an increase in power plant emissions in Arizona will not occur under the current proposal. Second those emission increase and reductions in power plant emissions are irrelevant on the expansion of the CRS and only serves to confuse the decision maker and the public as to the true impacts of the CRS expansions.

The DEIR states that the first component of the No Project Alternative is the continuation of ongoing demand-side actions, including energy conservation and distributed generation (DG). These actions would result in possible localized air quality impacts as a result of development of DG units by energy consumers. This would be the case if fossil-fuel fired or other combustion or thermal DG technologies become more widespread. The DEIR ignores the potential for rooftop solar and substation located solar arrays which would eliminate the need for additional transmission lines and large scale solar generating facilities in the desert environment and eliminates all of the impacts identified in the DEIR and the significant impacts of these large scale solar projects. The DEIR also fails to consider the enormous amount of energy consumption that could be achieved by shifting ratepayer resources away from the central station solar arrays and large desert renewable projects. .

The DEI then speculates that the second component of the No Project Alternative is the continuation of supply-side actions, resulting in potentially increased generation within California or increased transmission into California to serve anticipated growth in electricity consumption.

The impacts of new power plants and new transmission lines could add air pollutants contributing to existing nonattainment conditions or violations of ambient air quality standards, if they occur in areas of substantial existing pollution. Although construction and operation of new power plants and transmission lines may occur, their locations and development schedules cannot be predicted. This is unlikely if in fact the regulators do enforce the loading order and fulfill future electrical demand with energy efficiency measure and distributed rooftop and substation solar arrays.

CERTIFICATE OF SERVICE

I, the undersigned, certify that I served the foregoing **CALIFORNIANS FOR RENEWABLE ENERGY'S INITIAL COMMENTS ON SUPPLEMENTAL DRAFT ENVIRONMENTAL IMPACT REPORT FOR COLORADO RIVER SUBSTATION EXPANSION** on the persons/parties listed, in the manner indicated, on the attached Service List.

Date: April 8, 2011. s/ Cory J. Briggs

Service List for A10-11-005
(Last Update: 7-Apr-2011)

robert.pontelle@alston.com	ROBERT	PONTELLE
lcottle@winston.com	LISA A.	COTTLE
michaelboyd@sbcglobal.net	MICHAEL E.	BOYD
rl@eslawfirm.com	RONALD	LIEBERT
angela.whatley@sce.com	ANGELA	WHATLEY
case.admin@sce.com	CASE	ADMINISTRATION
richard.tom@sce.com	RICHARD	TOM
cory@briggslawcorp.com	CORY J.	BRIGGS
cem@newsdata.com	California Energy Markets	
harron@solarmillennium.com	ALICE L.	HARRON
cressner@solarmillennium.com	MICHAEL	CRESSNER
bcb@cpuc.ca.gov	Billie C.	Blanchard
ec2@cpuc.ca.gov	Elaine Chan	Lau
hsy@cpuc.ca.gov	Hallie	Yacknin
dpv2@aspeneg.com	Billie	Blanchard