Powers Engineering

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California Energy Commission
Dockets Office MS-4
Re: Docket No. 11-IEP-1G
1516 Ninth Street
Sacramento, CA 95814-5512
docket@energy.state.ca.us

Subject: Docket No. 11-IEP-1G, Additional Powers Engineering Comments on CEC May 9, 2011 Distributed Generation Workshop

Dear California Energy Commission:

This letter provides additional comments by Powers Engineering regarding: 1) achievement of the state's target of 12,000 MW of distributed renewable energy by 2020, and 2) the preliminary allocation by the Governor's Office of 2,000 MW of this statewide target to the San Diego area.

1. **Residential PV is the most cost-effective PV for residential IOU ratepayers with high levels of consumption**

Residential PV has a high value to the homeowner with higher-than-average electricity consumption. California investor-owned utility (IOU) residential customers buy 20,000 to 25,000 GWh per year at $0.30/kWh (PG&E Tier 3 rate) or greater. This is equivalent to 10,000 to12,000 MW_{ac} of PV capacity statewide. An April 2011 Lawrence Berkeley National Laboratory study of the effect of a PV system on home value indicates the assessed value of home increases by at least as much as capital cost of PV system when it is installed.[1] As a result, even though the $/kW installed cost of a residential PV system is higher than a commercial rooftop system, with a cost-of-energy in the range of $0.20 - $0.25/kWh without incentives, this PV production offsets utility electricity purchased at about $0.30/kWh, and the value of the home increases by at least the value of the PV system at the time it is installed. This is such a financially attractive arrangement for the homeowner that widespread access to Property Assessed Clean Energy (PACE) financing, or equivalent utility on-bill financing, would allow much of this 10,000 to12,000 MW_{ac} residential PV market potential to be realized.

2. **IOU concerns about limited "low hanging" PV interconnection capacity are misplaced**

The 2007 CEC Integrated Energy Policy Report (IEPR, pp. 155-156) called for all new and upgraded distribution substations to be smart grid compatible, and that utilities should be

[1] Lawrence Berkeley National Laboratory, *An Analysis of the Effects of Residential Photovoltaic Energy Systems on Home Sales Prices in California*, LBNL-4476E, April 2011.

required to conduct cost/benefit analysis if proposing not to incorporate smart grid features, like 100 percent bidirectional capability, in all upgrades/new builds. This should be required utility practice to avoid distribution substations creating an artificial bottleneck to DG renewable energy development. The KEMA presentation at the May 9th workshop, "European Experience Integrating Large Amounts of DG Renewable Energy," made three important points on this issue:

- AC grid voltage levels are in Germany and Spain are comparable to California.
- German distribution substations incorporate bi-directional relays/circuit breakers as a standard practice, allowing full bi-directional flow in each direction.
- Older electro-mechanical relays/circuit breakers used in many California distribution substations need to be replaced (to achieve bi-directional flow), though substations with newer solid-state relays may only need relay reprogramming.

Although U.S. KEMA representative Korinek stated there was less "low hanging" PV interconnection potential in California than Germany in oral comments at the end of the workshop, neither the KEMA written materials nor any written information presented by PG&E, SCE, SDG&E, or CAISO support this contention. The IOU representatives indicated orally that many substations, especially in urban areas, were still using very old electro-mechanical relays that are replaced as they fail. No information was provided by the utilities on the cost of a methodical change-out of electro-mechanical relays for solid-state bidirectional relays (4-quadrant relays). Based on research by Powers Engineering of actual substation protective device retrofits, the cost of a comprehensive retrofit of all relays/circuit breakers at a typical 100 MW distribution substation would be in the range of $500,000 or less. This is a very minor expense relative to the value of 100 MW of distributed PV.

3. The "all-in" avoided cost to IOUs of solar PV power is greater than $0.20/kWh

The "all-in" avoided cost to IOUs of solar PV power is greater than $0.20/kWh, yet CPUC and the IOUs assert the avoided cost is at $0.10/kWh or less. The Powers Engineering supporting calculations for a solar PV avoided cost greater than $0.20/kWh, using the January 2010 CEC modeled levelized cost of energy from a natural gas combined cycle plant as the foundation, is provided in Attachment 1.

4. SDG&E claims that a 2,000 MW distributed renewable energy allocation is not achievable are unsupported

SDG&E's Jim Avery stated in oral comments that SDG&E will be importing 1,000 MW of solar power from Imperial County on the proposed Sunrise Powerlink transmission line, and that an additional 2,000 MW of distributed PV could result in net exports of solar power from SDG&E territory under light load conditions. SDG&E indicated this solar export scenario would violate transmission line limits, violate the terms of Industrial Development Bonds used by SDG&E to construct the transmission lines, and potentially require significant transmission upgrades. None of these assertions were supported in Mr. Avery's PowerPoint presentation. SDG&E has made no commitment to transmit any solar power over the Sunrise Powerlink. It is because SDG&E

would not commit to any level of renewable energy on the Sunrise Powerlink that lead CPUC Commissioner Dian Grueneich voted against the project. See Attachment 2, dissent of lead CPUC Commissioner Dian Grueneich to the December 18, 2008 CPUC decision to approve the transmission line. One major advantage of 2,000 MW of local solar is that there would be no question whether this solar energy is actually being delivered to San Diego. Finally, the distributed PV would be owned by third parties, not SDG&E, and therefore bond restrictions on SDG&E selling power from its plants for export over bond-financed transmission lines would not be an issue.

5. SDG&E claims that the intermittency of distributed PV causes problems is unsupported

SDG&E's Avery presents two slides that purport to show the difficulty SDG&E is having: 1) forecasting distributed PV output due to its intermittency, and 2) regulating voltage due to PV intermittency. No supporting documentation is provided by SDG&E to put these graphics in context. These graphics may have had more impact if KEMA had not shown in its subsequent presentation that Germany is absorbing approximately 15,000 MW of distributed PV, about 150 times the PV capacity in SDG&E service territory, with no significant difficulty. In its two slides, SDG&E appears to be showing the variation in output from a single PV system on partly cloudy day(s) in the spring of 2010. There are thousands of individual PV systems in SDG&E territory. A more useful exercise by SDG&E would have been to present the collective output of the installed PV capacity in the San Diego area on the same partly cloudy day(s) in the spring of 2010, and also to indicate the peak SDG&E load on the days that are referenced in the PowerPoint graphics.

6. **The San Diego solar resource is fully available at times of peak demand**

Global irradiance, also known as solar insolation, is a measure of the solar intensity at the earth's surface at a specific site at a specific time of day. Clouds reduce the amount of irradiance reaching the earth's surface. Powers Engineering selected the Montgomery Field Airport in San Diego as sample site to evaluate whether cloud cover had a significant impact on PV system output on peak demand days in the San Diego area.

Summer of 2007 hour-by-hour global irradiance data and hour-by-hour cloud cover data was analyzed for Montgomery Field.[2,3] 2007 was selected as the study year because hour-by-hour global irradiance data is publicly available for 2007 at no cost. Actual expected hour-to-hour

[2] Solar Anywhere website, hour-by-hour global irradiance data for 2007: https://www.solaranywhere.com/Public/SelectData.aspx

[3] Weather Warehouse website, U.S. Weather Service hour-by-hour cloud cover data for U.S. weather station sites. Data purchased for June 14, 2007 through September 5, 2007 period to capture all PG&E peak events when CAISO load was above 40,000 MW. Weather Warehouse reports the highest cloud cover percentage within the cloud cover interval registered in a given hour. For example, the first interval is 0 – 25 percent cloud cover. The Weather Warehouse dataset lists 25 percent cloud cover instead of the average value of 12.5 percent if cloud cover falls within the 0 – 25 percent range. Powers Engineering used the average cloud cover value for comparison with the actual ground-level global irradiance.

global irradiance at specific sites is determined from weather satellite images that record cloud density. The actual modeled irradiance at the Montgomery Airport was divided by the clear day global irradiance expected for the same day and hour at each of those sites to calculate the reduction in solar intensity due to clouds.

The results of this comparison are that cloud cover was not a significant factor during the highest peak demand hours of the year in San Diego. The solar resource strength during peak demand hours in SDG&E service territory in 2007 is shown in Attachment 3. During periods of peak demand, the solar resource in the San Diego is fully available and reliable.

Thank you for this opportunity to provide additional comments on the May 9, 2011 workshop on achieving the 12,000 MW distributed renewable energy target by 2020.

Regards,

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Calculating What Distributed PV Is Worth

A representative avoided cost for a solar PV system, using PG&E service territory as an example, can be calculated by adding: 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 T&D costs that are avoided when a PV system substitutes for grid power.

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 the 2009 MPR was developed.[1] 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.[2] The CEC also examined 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.[3]

The CPUC currently assumes a hypothetical capacity factor of 92 percent for a combined cycle unit when calculating the MPR.[4] 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.[5] 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 1 using the CEC combined cycle LCOE estimates.[6]

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. 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.[7] Given the average start-up date for the PG&E gas-

Table 1. 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
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.

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.

The generation of power at or near the point-of-use, whether it is solar PV or CHP, eliminates the transmission line losses that would occur if the electricity is imported from more distant sources to serve the same load. The value of the line losses avoided by use of DG in PG&E territory is approximately $10/MWh.[8]

The addition of local generation also relieves load on the local distribution substation and the transmission line(s) serving that distribution substation. This effect is more pronounced in areas with inadequate transmission, or distribution substations approaching their capacity at times of peak demand. 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. Ten separate PG&E divisions serve the nine-county Bay Area. The E3 model calculates energy efficiency avoided cost for each of these PG&E divisions. These T&D avoided costs are shown in Table 2.[9]

Table 2. Energy Efficiency T&D Avoided Costs in PG&E Divisions in the Bay Area

PG&E Division	T&D avoided cost ($/MWh)	Group
North Coast	27.84	1
North Bay	25.34	1
Sacramento	33.11	1
Diablo	30.67	1
Mission	37.57	1
San Jose	24.62	1
De Anza	32.35	1
Peninsula	11.16	2
San Francisco	9.02	2
East Bay	6.18	2

The average energy efficiency T&D avoided cost in Group 1 divisions is approximately $30/MWh. The average energy efficiency T&D avoided cost in Group 2 divisions is approximately $10/MWh. This avoided T&D credit is equally applicable to solar PV or CHP to the extent they are available during peak demand periods.

The T&D system is designed to meet peak demand loads. *California Solar Initiative* fixed PV systems in PG&E service territory have a demonstrated availability during the 4 pm to 5 pm peak hour of summer demand of more than 50 percent.[10] The peak availability of fixed PV is conservatively assumed to be 50 percent in BASE 2020. Therefore, the full avoided T&D value of $30/MWh in Group 1 areas and $10/MWh in Group 2 areas must be multiplied by 0.50 to accurately reflect the avoided T&D value of fixed PV. This means that the PV T&D avoided cost would be $15/MWh in Group 1 areas and $5/MWh in Group 2 areas. CHP would be credited with the full avoided T&D value, as CHP is fully available at the summer peak.

As noted, the GHG emissions component of the MPR is $15 per ton of CO_2. This converts to a cost adder of $6/MWh.[11]

The solar PV avoided cost calculation is:[12]

Avoided cost = (CEC LCOE × TOD factor) + CO_2 adder + avoided line losses + (avoided T&D × resource availability at peak)

Solar PV avoided cost, Group 1 area = ($158/MWh × 1.24) + $6/MWh + $10/MWh + $15/MWh
= $227/MWh

Solar PV avoided cost, Group 2 area = ($158/MWh × 1.24) + $6/MWh + $10/MWh + $5/MWh
= $217/MWh

The solar PV value to PG&E is $227/MWh, or $0.227/kWh, in Group 1 areas and $217/kWh, or $0.217/kWh, in Group 2 areas. Any PV project or program with a tariff of less than $0.227/kWh in Group 1 areas in 2011, or $0.217/kWh in Group 2 areas, is a lower-cost resource than buying the same electricity from PG&E.

The CEC forecasts a 36 percent rise in the LCOE for a new combined cycle plant between 2009 and 2018.[13] In contrast, PV panel prices have declined by as much as two-thirds over the last three years.[14] Prices for PV are forecast to continue drop by 15 percent per year until 2015 due to oversupply and cheaper production.[15]

Calculating What CHP Is Worth

The avoided cost to PG&E of CHP generation is somewhat different than that of PV. PV is a daytime resource with maximum output in the summer months. CHP is a round-the-clock baseload resource. For this reason, the TOD multiplier for CHP is 1.0. CHP can also be available continuously at rated capacity during the summer peak. CHP is therefore accorded full credit for avoided T&D expenditures. The CHP avoided cost is:

CHP avoided cost, Group 1 = $158/MWh × 1.0 + $10/MWh + $30/MWh × 1.0 = $198/MWh

CHP avoided cost, Group 2 = $158/MWh × 1.0 + $10/MWh + $10/MWh × 1.0 = $178/MWh

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[1] CPUC MPR webpage, 2009 MPR Documents, 2009 MPR Model, "Install_Cap" tab: http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr.
[2] CEC, *Comparative Costs of California Central Station Electricity Generation* , January 2010, Appendix B.
[3] Ibid, Tables 11 - 13.
[4] CPUC MPR webpage, 2009 MPR Documents, 2009 MPR Model: http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr.
[5] 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.
[6] 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.
[7] 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.
[8] See Table 7-1. Base load transmission line losses are 5 percent. The cost-of-energy from a remote solar thermal plant is \$202/MWh. Therefore the value of avoided transmission line losses = 0.05 × \$202/MWh = \$10.1/MWh.
[9] 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\$).
[10] 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 pm to 5 pm.
[11] CPUC MPR webpage, 2009 MPR Documents, 2009 MPR Model, Appendix F – Non-Gas Inputs: http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr. Year 1 heat rate is 6,879 Btu/kWh (6.879 MMBtu/MWh). Natural gas CO_2 emission rate is 117 lb CO_2/MMBtu. Therefore CO_2 emission rate is 6.879 MMBtu/MWh x 117 lb CO_2/MMBtu = 805 lb CO_2/MWh (0.40 ton CO_2/MWh). Cost of greenhouse gas adder in MPR is 0.40 ton CO_2/MWh x \$15/ton CO_2 = \$6/MWh.
[12] Application 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, p. 3. **"**The avoided line loss factor and avoided T&D costs are determined by applying the representative solar output profiles to the hourly line loss factors and avoided T&D costs included in the Commission's most recently adopted avoided cost model for energy efficiency resources (the E3 avoided cost model)."
[13] CEC, *Comparative Costs of California Central Station Electricity Generation* , January 2010, Table 1, Table 5. Resource is 500 MW unfired merchant combined cycle plant.
[14] New York Times, *Solar Panel Maker Moves Work to China*, January 14, 2011. "World (solar panel) prices have fallen as much as two-thirds in the last three years — including a drop of 10 percent during last year's fourth quarter alone."
[15] UPI.com, *Half of German solar firms could go under*, September 29, 2010.

Dissent of Commissioner Dian M. Grueneich

Overview

I dissent from today's majority decision to approve the $2 billion Sunrise Powerlink Transmission Project (Sunrise) because it fails to include a clean energy guarantee even though the legal, factual, and policy basis for Sunrise is to deliver renewable resources. My Alternate proposed decision contained such a provision and explained in detail why this requirement was both workable and necessary. The text of that renewable requirement is attached hereto as Attachment A.

Because the majority decision does not include such a renewable requirement, I cannot support it. Without a renewable requirement, we spend billions of ratepayer money on a new transmission line that provides no guarantee of benefits to San Diego Gas and Electric Company (SDG&E) ratepayers, can be used to transmit non-renewable energy, and may well undercut the state's global warming goals. We also miss a major opportunity to create a vibrant green collar economy in Imperial Valley, and risk exporting these skilled jobs across our borders.

The majority decision puts its faith – and ratepayer money - in expectations for the invisible hand of market forces to produce the results the Commission desires, in promises of possible reforms, and in waiting to see what happens while hoping for the best. As the Assigned Commissioner to this case, this "just trust us" approach is one I cannot support.

Discussion

The majority decision finds that Sunrise is not needed for reliability in San Diego until at least 2014 nor is it needed to meet a 20% Renewable

Portfolio Standard (RPS). I agree. SDG&E has already received more than enough offers for renewable projects that do not need Sunrise to fulfill its entire RPS obligation of 20% by 2010.[1] The record for this case also shows that Sunrise would actually increase costs to meet the RPS target of 20% by approximately $90 million. In sum, the majority decision agrees with my Alternate proposed decision that this massive investment of ratepayer money cannot be justified based on near term reliability or 20% RPS needs.

The basis for the majority decision's approval of Sunrise is that the line is needed to meet a 33% RPS and that doing so provides significant economic, reliability and greenhouse gas (GHG) reduction benefits. The California Independent System Operator (CAISO) projects that Sunrise can facilitate development of over 1,900 MW of Imperial Valley renewable resources between 2011 and 2015, including 1,000 MW of high capacity-factor geothermal resources. According to the record in this case, if these resources are developed and delivered on Sunrise, Sunrise will generate $94 million per year in net benefits for ratepayers.

However, the majority decision does not impose any enforceable obligations on SDG&E to develop renewable resources or to carry them over Sunrise. The Commission's decision is silent regarding any requirements for SDG&E to develop any renewables to be transmitted over Sunrise, to contract for any new Imperial Valley renewable resources, or to conduct any procurement activities specific to Imperial Valley. It does not state any commitment by this Commission, or for SDG&E, to

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[1] For example, SDG&E has placed enough in-state projects north of the San Onofre Nuclear Generating Station (SONGs) on its short list to meet its full 20% RPS obligation. These projects do not require Sunrise.

ensure a specific level of renewable development in the Imperial Valley will be carried over Sunrise, even though the legal, factual, and policy rationale for approving Sunrise hinges on success in these matters. In these difficult times, where regulators' failure to regulate has contributed to major financial crises, the majority decision to trust instead of imposing meaningful requirements is inappropriate.

With the majority decision, this Commission will wait and see what happens in our usual procurement process for 2009. If there are no or few bids from Imperial Valley developers, we will consider proposals that our staff monitor what is happening in the Imperial Valley and that the utilities hold bidders conferences in their procurement processes, and perhaps require that the utilities short list any Imperial Valley bids that they receive in 2010, if they do receive any at all.

The California ratepayers who will fund Sunrise cannot afford "trust us" as a business justification for this hugely expensive line. The history of our RPS procurement to date, and for SDG&E in particular, has been criticized by many as too slow and based more on contracts - or promises of contracts - than renewable delivery. In addition, CAISO itself states that delay in procurement of Imperial Valley renewables by only one year will reduce Sunrise's benefits by $11 million per year. Further, the RPS statute clearly intended that the majority of the renewable resources would be in state. Public Utilities Code Section 399.11 specifies that the RPS can protect public health and improve environmental quality throughout the state, stimulate sustainable economic development, create new employment opportunities, and reduce reliance on imported fuels. According to a recent study on green energy jobs, a full build out of renewable potential in Imperial Valley could result in thousands of new jobs in Imperial County.[2] Imperial County had a 22.6 percent unemployment rate in June, the highest in California.

There are three things that needed to have been included in the Sunrise decision to meet the promise of Sunrise as a renewable line. First, the decision needed to include specific requirements for SDG&E to develop Imperial Valley renewables. That is missing from the majority decision. Second, the decision needed to include firm commitments from this Commission to expand Imperial Valley renewable development to our other electric investor-owned utilities at a specified level consistent with the record in this decision. That is also missing from the majority decision. And, finally, the decision needed to mandate the first two items starting with procurement requirements in 2009. And, that too is missing from the majority decision.

The Commission's decision cites the off-the-record representations of SDG&E's Chief Executive Officer that SDG&E will voluntarily set a 33% RPS standard for itself, replace failed existing Imperial Valley contracts with new Imperial Valley renewables, and refrain from using Sunrise for coal fired generation contracts. However, the majority decision does not mandate that SDG&E comply with its own representations.

At a 33% RPS, Sunrise will generate $94 million per year in ratepayer benefits. However, the major assumption underlying this net benefit calculation is the development of new, high capacity renewable

[2] "Harvesting California's Renewable Energy Resources: A Green Jobs Business Plan," by Peter Asmus, Center for Energy Efficiency and Renewable Technologies, August 15, 2008, p. 23, www.cleanpower.org.

resources – 1,900 MW operational by 2015 - in the Imperial Valley. Without this development, the economic benefits of Sunrise disappear. The linkage is simple –SDG&E ratepayers and Californians as a whole will receive the economic, reliability and GHG emission benefits of Sunrise if – but only if -- Imperial Valley renewables are developed at the levels and within the timeframe projected by the CAISO. Further, the distinction between Imperial Valley resources and resources in other states or outside the United States is important. With Sunrise, the San Diego local reliability area will include the Imperial Valley substation; therefore, SDG&E's ratepayers will receive free reliability benefits from renewables that connect to that substation that they would otherwise have to purchase from other resources.

SDG&E's current contracts for Imperial Valley will only generate about 20% of the energy that Sunrise is capable of delivering, assuming these projects are successfully developed, constructed, and operate as proposed. These proposed Imperial Valley renewable projects, which would generate 459 MWs, are far less than the 1,900 MW of Imperial Valley renewable development that the CAISO assumed would be operational by 2015. Of the amount under contract, only 60 MW is high capacity-factor geothermal resources, compared to development of the 1,000 MW of geothermal upon which the CAISO analysis – and Sunrise approval – is based.

Specific requirements to develop renewables are also needed because the record shows that Sunrise could carry existing fossil-fired generation and facilitate the development of new fossil-fired resources outside the state. Existing transmission lines will connect Sunrise to out-of state resources, not only in the Southwestern U.S. but also to two existing gas fired plants totaling over 1,000 MW of capacity in Baja California in Mexico. Sempra Energy through its unregulated affiliates owns and operates one of these facilities and also owns the Liquified Natural Gas (LNG) facilities that can provide natural gas to these plants.

As set forth in Attachment A hereto, my Alternate proposed decision would have imposed a 3,500 GWH/year procurement requirement on SDG&E to be acquired through existing contracts, bilateral negotiations, and a 2009 request for offers (RFO) in Imperial Valley. This amount is well within the amount of Imperial Valley renewables identified by the CAISO. My Alternate proposed decision also committed this agency to require Southern California Edison Company and Pacific Gas and Electric Company to issue Imperial Valley RFOs in 2010 in a combined amount of approximately 6,000 GWH/year, enough to achieve the level of renewable projects that the CAISO has claimed will be facilitated by Sunrise and is necessary to achieve ratepayer benefits from Sunrise. My Alternate proposed decision provided flexibility in procurement and also committed to include measures and conditions for the Imperial Valley RFOs to mitigate market power, protect ratepayers from unreasonable costs, and apply any newly developed contract viability rules to these resources.

All of these requirements are reasonable, all are workable, and most importantly they are not based on statements of hoped for outcomes, consideration of possible future regulatory actions, and undefined and unenforceable promises.

However, under any scenario that approves Sunrise, one group will still get benefits – SDG&E shareholders. They will receive approximately $1.5 billion over the lifetime of Sunrise as their rate of return for the ratepayer funded capital investment, whether or not Sunrise is ever used to deliver any renewable power.

Conclusion

Despite the deepening recession, the foreclosure crisis, growing unemployment rates, and steadily increasing electric service shut off rates, the majority decision imposes a requirement on SDG&E ratepayers to fund the $2 billion cost of Sunrise and the 11.5 percent rate of return for SDG&E shareholders. This is not our money, it is not SDG&E's money, it is ratepayer money. We have an obligation to ensure that SDG&E ratepayers, and not just shareholders, see a return on their investment.
I am not willing to risk billions of ratepayer money to the invisible hand of the market. I cannot, in good conscience, rely on promises to consider possible proposals for reform in our procurement process in the future, when the evidentiary basis for our decision so clearly depends upon development of Imperial Valley renewables at specific levels in specific timeframes.

Consequently, I dissent.

Dated December 18, 2008, at San Francisco, California.

/s/ DIAN M. GRUENEICH
Dian M. Grueneich
Commissioner

Attachment 3. Solar Resource Intensity at Montgomery Field Airport During 2007 CAISO Peak Load Events

GI = Global Irradiance

CAISO 2007 Peak Load Events			SDG&E Load	Solar Intensity at Montgomery Field Airport (San Diego)			
2007 peak day/hour	at hour ending:	CAISO load, MW	SDG&E load, MW	Closest clear day at same hour	GI on clear day at same hour	Actual GI at peak hour of interest	% GI at peak hour of interest divided by clear day GI at same hour
6/14/2007	15	40,895	3,094	6/14/07, 15	739	739	100%
7/2/2007	16	41,485	3,559	7/2/07, 16	553	553	100%
7/3/2007	15	42,748	3,517	7/3/07, 15	736	736	100%
7/5/2007	17	44,696	3,294	7/5/07, 17	338	338	100%
7/6/2007	15	43,696	3,360	7/6/07, 15	712	712	100%
7/31/2007	14	41,834	3,369	7/31/07, 14	847	860	102%
8/1/2007	15	41,710	3,402	8/1/07, 15	704	704	100%
8/2/2007	16	42,113	3,691	8/2/07, 16	518	518	100%
8/3/2007	16	42,952	3,675	8/3/07, 16	522	522	100%
8/13/2007	16	41,996	3,900	8/13/07, 16	487	487	100%
8/14/2007	16	42,889	3,837	8/14/07, 16	480	480	100%
8/15/2007	16	43,481	4,106	8/15/07, 16	483	483	100%
8/16/2007	15	42,951	4,102	8/16/07, 15	678	678	100%
8/17/2007	15	42,439	4,053	8/17/07, 15	675	675	100%
8/20/2007	16	44,294	4,243	8/20/07, 16	456	456	100%
8/21/2007	16	44,707	4,134	8/21/07, 16	452	452	100%
8/22/2007	15	43,478	3,770	8/22/07, 15	632	632	100%
8/23/2007	14	42,195	3,530	8/23/07, 14	798	798	100%
8/24/2007	15	41,325	3,452	8/24/07, 15	641	641	100%
8/27/2007	15	42,245	3,908	8/27/07, 15	605	605	100%
8/28/2007	16	46,033	4,022	8/28/07, 16	439	439	100%
8/29/2007	16	48,553	4,129	8/29/07, 16	436	436	100%
8/30/2007	15	48,074	4,233	8/30/07, 15	613	613	100%
8/31/2007	16	48,823	4,439	8/31/07, 16	429	429	100%
9/1/2007	15	44,758	4,278	9/1/07, 15	621	621	100%
9/2/2007	15	43,940	4,312	9/2/07, 15	627	627	100%
9/3/2007	14	44,874	4,601	9/3/07, 14	780	780	100%
9/4/2007	14	44,616	4,501	9/4/07, 14	780	780	100%
9/5/2007	14	41,114	3,647	9/5/07, 14	780	775	99%

sources: CAISO OASIS 2007 database (hour-to-hour loads), and Solar Anywhere online 2007 database (hour-to-hour GI for ~100 km2 quadrants across U.S.)