**BEFORE THE PUBLIC UTILITIES COMMISSION**

**OF THE STATE OF CALIFORNIA**

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| Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans. | FILED<br>PUBLIC UTILITIES COMMISSION<br>MAY 6, 2010<br>SAN FRANCISCO, CALIFORNIA<br>RULEMAKING 10-05-006 |

**FIT COALITION**
**COMMENTS ON OIR AND ALJ RULING**

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June 3, 2010

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**COMMENTS ON OIR AND ALJ RULING**

The FIT Coalition submits these comments pursuant to the Order Instituting Rulemaking ("OIR") and the Administrative Law Judge's Initial Ruling ("ALJ Ruling") and pursuant to Rules 1.9 and 1.10 of the California Public Utilities Commission's ("Commission") Rules of Practice and Procedure.

The FIT Coalition is a California-based group focused on smart renewable energy policy. We advocate primarily for vigorous feed-in tariffs and "wholesale distributed generation," which is generation that connects to the distribution grid close to demand centers, thereby avoiding dependencies on transmission build-outs, transmission access charges, transmission line/congestion losses, and other costs/inefficiencies. Our members are active in proceedings at the Commission, Air Resources Board, Energy Commission, California Independent System Operator, the California Legislature, Congress, the Federal Energy Regulatory Commission, and in various local governments around California.

Our main points are as follows:

- All long-term procurement planning must take into account the substantial wholesale distributed generation that is likely to result from current and future policies and legislation; procurement policies should also encourage this type of generation as much as is possible because of its many desirable characteristics
- The Commission should remain vigilant and ensure that over-procurement of fossil fuel-fired resources doesn't unnecessarily result from efforts to integrate renewables or once-through cooling plant shutdowns
- We urge the Commission to include two additional issues in this proceeding: 1) consideration of optimal distribution line capital expenditures by IOUs and dissemination of wholesale distributed

generation access information; 2) oversight of potential conflicts of interest by investor-owned utilities in light of utility-owned renewable energy generation

# I. Comments

## a. Track I - Long-term System and Local Reliability Resource Plan

### i. Current And Pending Feed-In Tariff And Quasi-Feed-In Tariff Legislation

The FIT Coalition's primary interests are to promote feed-in tariffs and wholesale distributed generation ("WDG"), which consists of renewable energy projects interconnected on the distribution grid for direct sale of power to utilities. Feed-in tariffs and WDG are not explicit issues in the OIR or ALJ Ruling. We believe, however, that the 2010 LTPP cycle must continue the detailed consideration of WDG begun in the 2008 LTPP, in the "high distributed generation" scenario working group in the LTPP proceeding in 2007 and 2008 (R.08-02-007), examined as part of the 33% by 2020 RPS planning exercises. The FIT Coalitions' executive director, Craig Lewis, and the FIT Coalition's attorney in this proceeding, Tam Hunt, were both directly involved in this work in the 2008 LTPP through different organizations. The OIR and ALJ Ruling suggest that issues that were not finally resolved in the R.08-02-007 may be revived in this proceeding and it is our hope that this is the case with WDG and feed-in tariff procurement planning.

We were generally encouraged by the Commission's analysis in the 2008 LTPP on these issues, though there was room for improvement, particularly on the pricing analysis of WDG. History has proven us correct in our previous recommendations regarding pricing for WDG, with solar and wind technology costs dropping dramatically in the last two years. **We recommend, accordingly, that the Commission rigorously examine the potential for WDG to meet reliability and other needs in the IOU 2010 LTPP process**, along with the already-included consideration of energy efficiency.

A number of legislative matters support our recommendation, including the current weak feed-in tariff pursuant to AB 1969, and the slightly improved feed-in tariff under SB 32 (2009, Negrete-McLeod), which the Commission should be implementing later this year, as well as possible additional legislation sponsored by the FIT Coalition: AB 1106 (Fuentes). AB 1106 is a more robust feed-in tariff for projects up to 10 megawatts. Moreover, AB 1613, a cogeneration feed-in tariff for facilities 20 megawatts and under, has recently been implemented by the Commission and is the subject of two declaratory order proceedings at the Federal Energy Regulatory Commission (EL10-64 and EL10-66).

Moreover, the recently approved IOU PV programs, totaling 1,000 megawatts over five years for PG&E and SEC, and another 77 megawatts for SDG&E's pending program, will provide substantial opportunities for WDG over the next five years. These programs are quasi-feed-in tariffs because they lack a guaranteed price. Rather, developers must bid into a reverse auction process and allow the IOUs to select the winning bids.

This model is the same auction model proposed for the Commission's own feed-in tariff proposal, known as the Reverse Auction Mechanism ("RAM Proposal"). This is also, accordingly, a quasi-feed-in tariff because it lacks the guaranteed price of a true feed-in tariff. The Commission's RAM Proposal has no state-wide capacity limitation and will likely allow projects between 3 and 20 megawatts to bid into the system.

These programs, combined, will provide significant capacity additions over the coming years. We estimate up to 3,000 megawatts over the next five years from SB 32, AB 1106 (if passed into law) and the IOU PV programs, with another 2,000 megawatts or more from the California Solar Initiative (which is not technically WDG because it's on the demand side of the meter, but is still relevant to this analysis in terms of reliability, energy supply and peak supply). The RAM Proposal may result in significant additional capacity in coming years.

There are also a number of smaller projects coming online or proposed for the RPS program, SCE's Standard Offer program (20 megawatts and below) and other IOU programs, that will expand the state-wide portfolio of WDG in coming years.

All of these programs combined could lead to 10,000 megawatts or more of new WDG, a very substantial amount of new generation.

All of these feed-in tariffs or quasi-feed-in tariffs support our recommendation that WDG be rigorously examined in the current LTPP cycle for its ability to provide energy, capacity and resource adequacy, as well as possible other ancillary services, depending on the technology and location of each project.

#### ii. Integration of Renewables

The OIR states (p. 12): "[W]e anticipate that system requirements to: 1) integrate renewables, 2) support OTC policy implementation, 3) maintain local reliability, and 4) meet GHG goals will be primary drivers for any need for new resources identified in this proceeding." We agree with this statement in a broad sense. We caution the Commission, however, to ensure close oversight in this procurement process with respect to IOU plans to construct new fossil fuel-fired generation to integrate renewables, support OTC policy implementation, maintain local reliability and meet GHG goals. The financial temptation is for IOUs to over-state the need for new fossil generation to meet these needs, a temptation we have seen made manifest in the 2007 LTPPs, in which far too much fossil generation was approved as part of these LTPPs. History has shown critics of the 2007 LTPPs to be correct, as energy efficiency, conservation and the recession have resulted in far lower demand that was projected.

The discussion in the previous section applies equally to this section in that rapid WDG buildout in the coming years will likely have a profound impact on the four items listed on page 12 of the OIR. This is the case because WDG can help integrate renewables in many ways, including by providing peak power right where it is needed (with solar PV and coastal wind resources, in particular, which are reliable peak power providers), through broad geographic dispersion of resources across the grid (mitigating variability), reducing grid congestion and in various other ways. These same benefits help with OTC policy implementation, local reliability concerns and GHG reductions. See **Attachment A** for detailed testimony on local reliability issues and renewables integration with respect to the proposed Carlsbad Energy Center Project from the FIT Coalition's attorney in this proceeding (testifying in the Energy Commission hearing on behalf of EarthJustice and the Center for Biological Diversity).

The Commission's role on these procurement matters is "upstream," of course, in that the Commission will guide the current LTPP cycle. The Commission has no direct role in project permitting. However, the same concerns raised in Hunt's testimony before the Energy Commission are equally relevant to the procurement planning process.

### b. Track II – IOU Section 494.5 Bundled Plans

The FIT Coalition will provide comments on this Track at a later date.

### c. Track III – Rule and Policy Issues

#### i. Retirement of Once-Through Cooling Power Plants

As with the topic of renewables integration, we urge the Commission to be cautious in approving procurement plans for new generation to mitigate the shutdown of OTC power plants throughout the state. The default urge by IOUs will be to seek construction of new natural gas power plants identical or close to identical to the capacity of the retiring OTC power plant. We believe that each case should, of course, be examined on its own merits, and this examination is the role of the Energy Commission, not this Commission. But we also urge close scrutiny at the procurement planning level of system needs for retiring plants in each IOU's territory and a rigorous analysis of the ability of energy efficiency, WDG, and other renewables to eliminate or reduce the need for any new natural gas-fired generation.

The FIT Coalition will provide further comments on Track III issues as this proceeding progresses.

### d. Other Issues That Should be Included in This LTPP Cycle

The OIR in this proceeding sets the following standard for consideration of new issues in this LTPP (p. 18):

> *LTPP Scoping Standard.* The LTPP scoping standard is defined as follows:
>
> - Any procurement-related issue(s) not already considered in other procurement-related dockets in Table 1 below may be considered, subject to the following conditions. The issue(s) must:
>   - (1) Materially impact procurement policies, practices and/or procedures;
>   - (2) Be narrowly defined; and

(3) Demonstrate consistency with one or more of the LTPP proceeding goals set forth in R.08-02-007.

The five policy goals in R.08-02-007 are described in the Feb. 28, 2008 Order Instituting Rulemaking (p. 8) ("2008 OIR"):

1. Ensure the IOUs' plans meet their forecast load and balance the costs, benefits and price risks[1] of various policy directives (*e.g.*, EAP, reliability);
2. Develop policies so that each IOU can meet its forecast load and obtain procurement authority for new and existing resources to meet system and bundled forecast load, with sufficient lead time to enable efficient procurement of new resources;
3. Coordinate between the various generation cost[2] policy proceedings (*e.g.*, EE, DR, renewable portfolio standards) and to ensure that they are consistent and coherent;
4. Establish procurement rules that (a) shall be followed to ensure recovery of generation costs[3] in rates and (b) address issues of regulatory and/or market failure related to generation issues; and
5. Serve as the forum for comparing resource alternatives against each other, in terms of uniform criteria such as cost, risk, reliability, and environmental impact, in order to optimize California's electric resource portfolio.

We urge the Commission to include in this proceeding two additional issues that are not discussed in the OIR: 1) assuring the most prudent distribution grid capital expenditures and providing multi-year (5+ years) forward-looking visibility to the developer community about where WDG projects should be located, based on those distribution grid capital expenditure plans; 2) protecting against possible conflicts of interest now present in the

[1] Pub. Util. Code § 454.5(b)(1) specifies that procurement plans are to include an assessment of the price risk associated with the portfolio.

[2] In this context, "generation cost" is used to mean energy/electric service that is not distribution or transmission.

[3] *Id.*

renewable energy market in California. We believe both of these new issues satisfy the criteria set forth above.

### i. Assuring Smart Distribution Grid Capital Expenditures and Providing Multi-Year Forward-Looking Visibility Regarding WDG Project Siting

We believe this new issue meets the policy goals described in paragraphs 1, 2 and 5 of the 2008 OIR. Distribution grid expenditures are generally covered in the general rate proceedings. Distribution line access capacity and substation capacity has been discussed briefly as part of the Commission's ReDEC process. However, distribution grid expenditures as they relate to WDG, and public information about distribution line available capacity, are not covered jointly in any other proceeding, to our knowledge. Accordingly, **we urge full consideration of this issue in this proceeding**.

Even though a large number of WDG projects can be interconnected today to the distribution grid, it is not clear how much, when or where WDG projects may be interconnected, and at what cost. A key benefit of WDG is that distribution grid interconnection expenses, such as reconductoring, are borne by the developer, not ratepayers. Transmission grid upgrades are, to the contrary, borne by ratepayers. At issue here, however, is ensuring that distribution grid upgrades by IOUs are made in such a way as to maximize the amount of WDG that may be interconnected at low or no cost. So this is about optimization of ratepayer dollars with respect to distribution grid upgrades and ensuring adequate information is provided to WDG developers to allow for maximum buildout of these resources, in the least amount of time, and at the least cost to ratepayers.

### ii. Protecting Against Possible IOU Conflicts of Interest With Respect to Renewable Energy Development

We believe this new issue squarely meets the policy goal described in paragraph 4 of the 2008 OIR. Federal and state policies have changed in recent years in such a way as to allow IOUs to take a far more active role in renewable energy development than was previously possible. For example, the federal investment and production tax credits were not previously available to utilities; they now are. As another example, PG&E and SCE have obtained Commission approval for ownership of 250 megawatts each of solar PV projects, with another 250 megawatts for each utility to be owned by third parties, but selling power to the IOUs. The IOUs have some conflict of interest controls in place already. However, the **FIT Coalition is not convinced that there is adequate information available to third party market participants to assuage concerns about conflicts of interest or that there is sufficient oversight by the Commission to ensure that there is no actual conflict of interest**. There is certainly an appearance of a conflict of interest with some of these programs, particularly as it relates to distribution or transmission line access for new projects. The Commission should prioritize these issues in this proceeding or a related proceeding.

## II. Conclusion

For all the reasons discussed, we believe that WDG and feed-in tariffs should be featured prominently in this LTPP cycle. We look forward to further discussion.

Respectfully submitted,

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Dated: June 4, 2010

CERTIFICATE OF SERVICE

I hereby certify that I have served by electronic service a copy of the foregoing **FIT COALITION COMMENTS ON ALJ INITIAL RULING** on all known interested parties of record in R.10-05-006 included on the service list appended to the original document filed with this Commission. Service by first class U.S. mail has also been provided to those who have not provided an email address.

Dated at Santa Barbara, California, this 4th day of June, 2010.

Tamlyn Hunt

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**Attachment A: Hunt Testimony in Carlsbad Energy Center Project Proceeding**

**STATE OF CALIFORNIA**

**Energy Resources Conservation and Development Commission**

| In the Matter of:<br>APPLICATION FOR CERTIFICATION FOR CARLSBAD ENERGY CENTER PROJECT | DOCKET NO. 07-AFC-06 |
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***REBUTTAL TESTIMONY FOR TO THE OPENING TESTIMONY OF JIM MCINTOSH,***

**COMMENTS BY TAM HUNT, J.D., COMMUNITY RENEWABLE SOLUTIONS LLC**
**ON BEHALF OF INTERVENOR CENTER FOR BIOLOGICAL DIVERSITY**

January 11, 2010
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**STATE OF CALIFORNIA**

**Energy Resources Conservation and Development Commission**

| In the Matter of:<br>APPLICATION FOR CERTIFICATION FOR CARLSBAD ENERGY CENTER PROJECT | DOCKET NO. 07-AFC-06 |
|---|---|

***REBUTTAL TESTIMONY TO THE OPENING TESTIMONY OF JIM MCINTOSH***

**BY TAM HUNT, J.D., COMMUNITY RENEWABLE SOLUTIONS LLC ON BEHALF OF INTERVENOR CENTER FOR BIOLOGICAL DIVERSITY**

## INTRODUCTION

I am an attorney with substantial experience in California renewable energy and energy efficiency legislation and regulatory policy. I am California Bar-certified (218673). I currently am the managing member of Community Renewable Solutions LLC, a consulting and renewable energy project development firm. My firm is partnered with Pacific Wind Power (Solvang, California) in a joint venture focused on developing community-scale wind and solar (20 megawatts and under) in Central California.

From early 2005 to mid-2009, I was the Energy Program Director and Attorney for the Santa Barbara-based Community Environmental Council, a non-profit organization active in state and local energy policy. I appeared regularly at the California Public Utilities Commission, Energy Commission and Air Resources Board in proceedings related to renewable energy, energy efficiency, climate change and liquefied natural gas. I submitted written comments, legal briefs and testified in workshops and hearings on a wide range of issues, including the CPUC's implementation of AB 32, SB 1368, AB 2021 and many other laws. I also served as part of the "high distributed generation" scenario working group in the CPUC's long-term procurement proceeding in 2007 and 2008 (R.08-02-007).

I am the lead author of the Community Environmental Council's *A New Energy Direction: A Blueprint for Santa Barbara County*, an action plan for weaning Santa

Barbara County from fossil fuels by 2030 or sooner. I am also the lead author of the Community Environmental Council's report, *Does California Need Liquefied Natural Gas? The Potential for Energy Efficiency and Renewable Energy to Replace Future Natural Gas Demand.* I served on the American Institute of Architects' Committee on the Environment in 2007 and 2008, advising that group regarding the merits of various California bills related to green building and renewable energy.

I am a Lecturer at UC Santa Barbara's Bren School of Environmental Science & Management, where I teach 10-week courses on renewable energy law and policy and climate change law and policy. Last, I am a regular columnist for www.renewableenergyworld.com and www.energypulse.net.

**TESTIMONY**

## I. Summary

- A number of state-wide collaborative efforts, which are directly relevant to the proposed CECP, are currently underway and should be complete by early 2011; the McIntosh CAISO testimony and related Final Staff Assessment analyses are, accordingly, premature and incomplete
- The McIntosh CAISO testimony in this proceeding, in addition to being premature, is overly general, incomplete and inaccurate; for example, solar PV is well-established as a reliable peak power source and can help substantially in integrating wind power
- California's aggressive greenhouse gas and renewable energy mandates require "critical" scrutiny of any proposed new fossil fuel electricity generation
- The McIntosh CAISO testimony and the FSA fail to demonstrate that the proposed CECP is necessary to integrate renewable energy resources
- The Commission's most recent electricity demand forecast shows that the recession has obviated the need for about six power plants the size of the proposed CECP by 2018
- With this reduced demand forecast, the local reliability concerns should not be overshadowing the requisite environmental analysis.
- Adding unnecessary new fossil fuel electricity generation burdens ratepayers and makes renewable energy mandates more expensive

## II. The CAISO testimony in this proceeding is an overly generalized and faulty analysis

The CAISO testimony provided by Jim McIntosh is overly general, with no particularized analysis for the proposed CECP. There are many omissions in this testimony, including a failure to even mention "resource adequacy" requirements or the dramatic decline in forecasted energy demand throughout California from the current recession. More generally, the CAISO testimony's conclusions are premature in light of numerous current initiatives designed to assess with far greater specificity what California's grid reliability needs are, and how renewable energy projects resulting from the Governor's 33% by 2020 mandate can be integrated at the least cost to ratepayers.

### A. The CAISO testimony is premature in light of three statewide initiatives that are directly relevant to the CECP

There are at least three major ongoing efforts that are highly relevant to the CECP: 1) The California Transmission Planning Group (CTPG); 2) CAISO's own 33% by 2020 integration analysis; and 3) the Inter-Agency Analysis of Generation and Transmission Options for Eliminating Reliance upon Once-Through Cooling Power Plants. These three efforts are collaborative and all involve the Commission itself.

With respect to the first effort, the 2009 Integrated Energy Policy Report ("2009 IEPR") states with respect to the CTPG and new federal efforts (p. 202)[4]: "With federal funding, western sub-regional transmission planning groups are taking on enhanced planning roles, including preparation of an integrated 10-year subregional transmission plan. Successful development and engagement of the CTPG and participation of the California ISO are essential to find consensus on projects and analyses reflective of California interests." The CTPG plans to release its revised draft plan in February of 2010 and a final conceptual plan by May.[5]

With respect to the second effort, the CAISO's Renewable Energy Transmission Planning Process (RETPP), the 33% by 2020 renewable energy integration analysis is due in "late 2010, or early 2011."[6] The "Draft Final Proposal" was released on January 6, 2010.[7] This report describes the tasks of the RETPP:

> The central objective of the ISO's proposed renewable energy transmission planning process (RETPP) is to enhance the existing

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[4] 2009 IEPR at 202. Available at http://www.energy.ca.gov/2009publications/CEC-100-2009-003/CEC-100-2009-003-CMF.PDF.

[5] CAISO presentation, Dec. 8, 2009: "Getting to 33% RPS by 2020 through a Comprehensive Renewable Energy Transmission Planning Process (RETPP)." P. 9.

[6] Id.

[7] Online at http://www.caiso.com/2718/2718b2a210830.pdf.

> transmission planning and generation interconnection processes to promote the development of infrastructure needed to achieve the state's 33 percent renewable portfolio standard (RPS) by 2020. To this end, the proposed RETPP will: (1) develop a statewide conceptual transmission plan through collaboration among all transmission providers and owners in California; (2) finalize that plan for the ISO balancing authority area with sufficient detail both to establish needs and to elicit specific proposals to build the needed transmission; (3) establish, in the ISO tariff, access to renewable supply resources as a formal criterion for assessing need for specific transmission upgrades and approving their cost recovery through regulated rates; (4) enable transmission infrastructure development to move forward expeditiously and efficiently to support the state's environmental goals; (5) coordinate RETPP activities and milestones with key ongoing activities of the ISO's existing Order 890 compliant transmission planning process and the generation interconnection process in a practical way; and (6) provide opportunities for stakeholder participation and input to the process.

CAISO informed the RETPP working group convened on December 8, 2009, that the CAISO proposal is "still conceptual, many details to be developed."[8] This new 33% analysis comes on the heels of the 2007 CAISO study[9] cited by the CAISO testimony in the present proceeding. The CAISO 2007 study examined, however, the integration needs and costs of the 20% by 2010 renewable energy mandate and provided only the most generalized estimate of the costs for meeting the higher 33% by 2020 mandate.

With respect to the third effort, the Inter-Agency Analysis of Generation and Transmission Options for Eliminating Reliance upon Once-Through Cooling Power Plants is expected to produce a comprehensive plan for OTC mitigation in relation to electric system reliability concerns, though no date has been set yet for the final plan.[10]

**Accordingly, it is premature to make any decision regarding the merits of the proposed CECP; the Commission should wait until the CTPG and CAISO**

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[8] CAISO presentation, Dec. 8, 2009: "Getting to 33% RPS by 2020 through a Comprehensive Renewable Energy Transmission Planning Process (RETPP)." P. 9.

[9] CAISO, *Integration of Renewable Resources*, online at http://www.caiso.com/1ca5/1ca5a7a026270.pdf ("CAISO 2007 study").

[10] Implementation of Once-Through-Cooling Mitigation Through Energy Infrastruction Planning and Procurement, Draft Joint Agency Staff Paper. (July 2009) Available at: http://www.energy.ca.gov/2009publications/CEC-200-2009-013/CEC-200-2009-013-SD.PDF

**RETPP processes have completed their analyses in late 2010 or early 2011, and should probably also wait until the Inter-Agency Analysis of OTC issues is complete.**

This conclusion is reinforced by the Commission's 2009 California Energy Demand electricity forecast, described below, which shows that conservation due to the recession will, by itself, eliminate the need for the equivalent of six new power plants the size of the proposed CECP. With this reduced demand forecast, the state has additional breathing room regarding grid reliability concerns and can afford to take more time in finding the optimal means for meeting its renewable energy mandates and local reliability concerns – before locking in new fossil-fuel generation for future decades.

This conclusion is also reinforced by the new 2009 Integrated Energy Policy Report ("IEPR"), which states (p. 209, emphasis added):

> In the California ISO balancing authority area, formal resource adequacy requirements established by both the CPUC and California ISO provide a framework for evaluating reliability. However, the need for dispatchable power plants in specific locations to support the California ISO's local reliability needs <u>remains analytically opaque</u> and there is, as yet, no mechanism to ensure that the needed resources will be built.

### B. The CAISO testimony fails to establish that the CECP is necessary to balance additional renewable energy generation

#### 1. Resource adequacy requirements for California utilities

Resource adequacy requirements are imposed on utilities and CAISO in order avoid blackouts and brownouts resulting from insufficient power supplies during high demand. A May 2009 report for the Commission, from MRW Associates ("MRW report"), describes the desired procedure for evaluating greenhouse gas emissions from natural gas power plants.[11] The MRW report describes the resource adequacy ("RA") system in California (p. 29):

> A regulatory framework exists to ensure that resource decisions result in a reliable electric system. The key element of this framework is resource adequacy (RA) requirements, which are generally presented as reserve margins and can be

[11] MRW Associates, "Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California," (May, 2009).

> roughly divided as follows: planning versus operational reserve requirements and local versus regional reserve requirements. In general, planning reserve margins are imposed on load serving entities (LSE) at the state level with regulatory oversight from the California Public Utilities Commission (CPUC) and operational reserve margins are the responsibility of the grid operator under regulations from the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC) with oversight from FERC.

CPUC Decision 04-01-050 (2004) required all utilities to maintain 15-17% resource adequacy requirements, a level that has since been achieved by all utilities. RA requirements are not imposed only, or even primarily, for renewable energy integration, however. The MRW report states (p. 32): "Unscheduled outages provide a larger problem for transmission planning and are a principal motivation for resource adequacy planning." For example, the state's largest generation facilities, the nuclear power plants at San Onofre and Diablo Canyon (about 2,000 megawatts each) experience unscheduled outages not infrequently. In October of 2009, PG&E's Diablo Canyon Unit 1, with a capacity of 1,122 megawatts, was reduced to 50% capacity due to problems caused by a large storm.[12] This kind of incident happens on a fairly regular basis across the nation and afflicts all large power plants. As the MRW report states (pp. 32-33):

> If a large baseload plant were to go offline at the time of peak demand, system operators would likely struggle to supply power to meet demand, to maintain the proper operating frequency, and to avoid blackouts. In some cases the cause of an unexpected outage at a generator can be resolved within a short period of time, and the unit can be returned to duty quickly. In other cases, such as with nuclear power plants, an unexpected outage may be a symptom of a larger problem and may result in an outage on the order of months.

It is also important to note that the term "intermittency," generally used to describe wind and solar power, is a bit of a misnomer. As the International Energy Agency ("IEA") states in a major 2005 report, the more accurate term is "variability."[13] This is the case because renewables are not truly intermittent, in terms of completely starting and stopping on a regular or irregular schedule. Rather, they are <u>variable</u> because electricity generation generally ramps up and

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[12] Online at http://www.reuters.com/article/idUSN1554013320091015.

[13] IEA, *Variability of Wind Power and Other Renewables*, 2005.

down fairly smoothly. This is an important difference when compared to planned or unplanned power outages from large baseload or shoulder power plants because when these often very large plants shut down the entire generation is generally lost – there is no variable ramp down or ramp up, as is generally the case with wind and solar facilities.

### 2. California's renewable energy portfolio and geographic dispersion

California currently has about 2,500 megawatts of wind power on the grid. This constituted only 2.4% of the total system power in California in 2008.[14] Renewable energy as a whole constituted 10.6% in 2008 – a reduction from previous years due to load growth and a stagnation in new renewable energy resource growth in recent years. However, 4.5% of California's power came from geothermal resources, which are baseload resources.[15] Another 3.5% came from biomass and small hydro, which are high capacity factor resources (though not necessarily baseload). Only 0.2% came from solar power in 2008. Accordingly, only 2.6% (wind and solar) of California's total electricity resources came from variable renewable energy resources in 2008. This is substantially less than the state receives from its small fleet of two in-state and one out-of-state nuclear power plants (about 15%), large components of which may experience unplanned outages requiring major backup sources to ensure grid reliability.

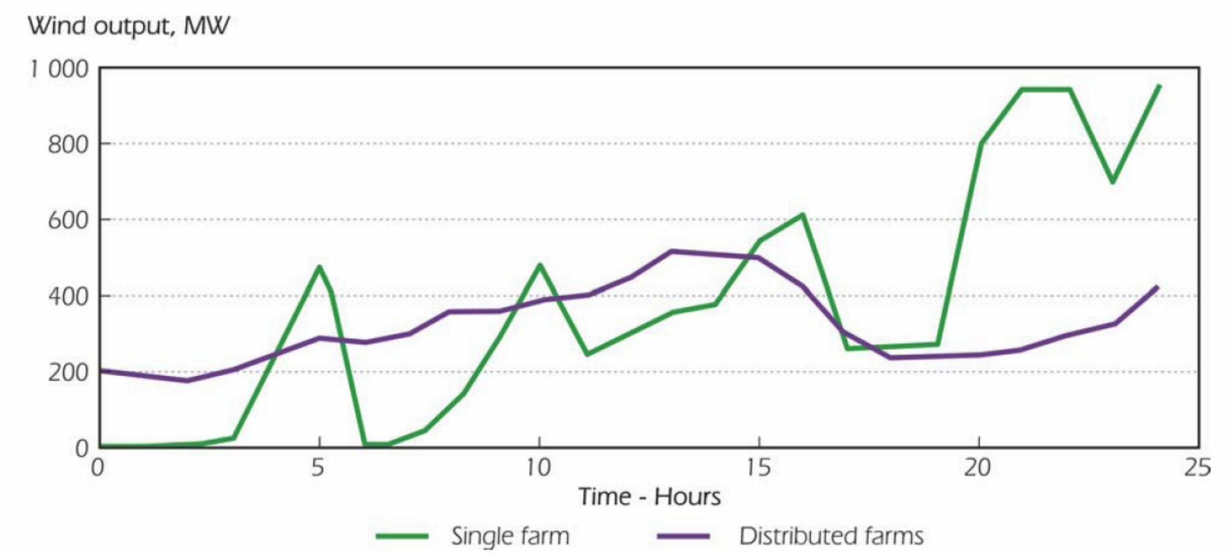
More importantly, however, wind and solar power are projected to provide about 60,000 gigawatt hours by 2020, or about 20% of the total system power, if the 33% by 2020 mandate is met. This will not all be variable generation, however, as significant energy storage projects are underway in conjunction with major wind and solar power projects. For example, both Southern California Edison and PG&E are planning to build energy storage projects pursuant to state and federal funding. PG&E received funds for a 300 megawatt "compressed air energy storage" project using salt formations near Bakersfield. Edison was awarded funds for an 8 megawatt lithium ion battery demonstration project.[16] Other companies, such as Solar Reserve, plan to include molten salt thermal storage facilities with their solar thermal power projects. Solar Reserve claims such storage facilities more than pay for themselves because they allow load shifting and sale of reliable power during peak demand times. Solar Reserve signed a contract with PG&E in December of 2009 for a 150 megawatt facility

[14] 2008 Net System Power report, Table 2, p. 5.
[15] Id.
[16] Online at http://www.energy.gov/news2009/documents2009/SG_Demo_Project_List_11.24.09.pdf (p.4).

near Blythe, California, which will include storage.[17] This contract will require CPUC approval before it is finalized.

Moreover, as the Western Interconnect builds wind and solar resources throughout its geographic extent, variable resources need less balancing generation than would be the case if all facilities were located in the same area. This is known as "geographic dispersion" and results from the fact that the sun shines and the wind blows at <u>different</u> times throughout the Western Interconnect. The IEA report cited above highlights geographic dispersion as a potent tool for reducing net variability of wind and solar resources (p. 20). The following figure shows the hypothetical results of geographic dispersion of 1,000 megawatts of wind (p. 20):

**Figure 3: The smoothing effects of geographical dispersion of a single wind farm and distributed wind farms, both rated at 1000MW (Mott MacDonald 2003:8)**




**In sum, assessing exactly what additional backup power facilities will be required to meet California's mandates, if any, by 2020 is a complex task.** Utility resource adequacy requirements (15-17%) allow integration of far more intermittent/variable wind and solar into the system than California has today, and **CAISO is following up on its 2007 study with a detailed examination of new transmission and balancing generation requirements for the 33% by 2020 renewable energy mandate, as discussed above.**

The CAISO testimony fails to provide any <u>quantitative</u> analysis pertinent to the CECP, and fail to mention that the CAISO, CTPG, and Inter-Agency OTC groups are currently engaged in major analyses that are highly relevant to the CECP.

[17] Online at http://www.solar-reserve.com/pressReleases/RicePPAPressRelease.pdf.

How much additional generation should utilities build into their resource adequacy portfolio? And where? And how does the proposed CECP fit into these requirements? These are highly important questions that have yet to be answered. Without answers to these questions, the CAISO 2007 study, and the CAISO testimony based upon it, are no help at all in making decisions on actual projects. What if 50 such projects were proposed in California? Under the CAISO testimony's analysis all such projects would, all else being equal, be considered beneficial for integrating renewable energy into the grid. This is clearly an inadequate analysis.

The CAISO testimony acknowledges that CAISO has not engaged in an "independent analysis of the GHG emissions impacts of the proposed CECP. However, … the proposed CECP's generation characteristics would foster the integration of renewable resources that will displace other less efficient fossil generation." (P. 10). As shown above, the CAISO testimony does not make the case that the proposed CECP is required to integrate renewable energy into the grid or that it will lead to a net reduction in GHG emissions. A particularized analysis is required to make this case and the CAISO testimony manifestly fails, under its own terms, in this regard.

### 3. The Final Staff Assessment also fails to demonstrate that the proposed CECP is necessary to integrate renewable energy resources

Based on the same theory as the CAISO testimony, the Final Staff Assessment ("FSA") Alternatives analysis makes two similar points (6-19): 1) the CECP is required to meet the expanding need for highly efficient dispatchable power plants in the San Diego load picket; and 2) the CECP will improve the San Diego region electrical system reliability by adding fast starting generation to respond to peak power demand and to integrate renewables. However, neither the FSA Alternatives analysis nor the CAISO testimony submitted in support of that analysis provides the specificity required to support these assertions. As discussed above, more analysis is required and is, in fact, underway with at least three state-wide efforts that relate directly to the proposed CECP.

The FSA GHG Analysis also states (4.1-100) that the "CECP would provide flexible peaking or mid-merit power necessary to integrate the growing generation from intermittent renewable sources, such as wind and solar generation."

However, the GHG Analysis fails to make the case that the CECP is necessary to integrate intermittent/variable wind or solar generation. As discussed further below, the dramatic drop in projected state-wide electricity demand by 2018-

2020, in the Commission's 2009 electricity demand forecast, obviates the need for about six power plants the size of CECP.

In order to determine the firm capacity necessary for integrating up to 20% wind and solar power by 2020, the CAISO 33% by 2020 analysis and CPTG process need to be completed, which should happen by early 2011. Indeed, the MRW report makes this exact point (p. 4, emphasis added):

> Currently no public studies provide estimates of amounts and types of ancillary services needed to support intermittent renewable generation under a 33 percent RPS. <u>Such studies are necessary</u> to provide a better understanding of the need for flexible generation in the next decade and beyond.

Accordingly, the GHG Analysis conclusion that the proposed CECP is necessary to meet either the 2010 or 2020 renewable energy mandates, is unsupported by the analysis provided. The Commission must await completion of the CAISO 33% by 2020 and CPTG analyses before it can proclaim the value of the CECP in fostering the integration of renewables.

The joint agency staff paper on OTC mitigation (CEC-200-2009-013-SD) also supports this conclusion with its discussion of the impact of AB 32 on fossil fuel generation (p. 5):

> The energy industry's compliance with the detailed regulations that will implement the California Air Resources Board AB 32 *Climate Change Scoping Plan* presumably leads to a lower electricity demand forecast, because additional energy efficiency measures will reduce demand and rooftop photovoltaic and other distributed generation will displace sales of electricity from the bulk power system to end users. A lower demand forecast would require fewer central station generating facilities within load pockets to satisfy reliability criteria.

Indeed, the GHG Analysis itself states that all new generation must come from renewable energy to meet the 33% by 2020 RPS mandate (4.1-115): "[A]ll growth will need to come from renewable resources to achieve the 33 percent RPS, and some existing and new fossil units will generate less energy than they currently do, given the expected growth in retail sales."[18]

[18] FSA footnote 6 (4.1-115) makes the point that there is still a need to increase short term fast ramping and starting natural gas generation to integrate renewable energy, even though on a net basis all new generation must be renewable. This is, however, simply a re-statement of the GHG Anlysis' broader point, which is unsupported by current statewide or local analyses.

The GHG Analysis describes (4.1-116) how the state must retire, curtail or otherwise eliminate about 36,000 gigawatt hours (GWh) of fossil fuel electricity by 2020 to meet the 33% by 2020 renewable energy mandate. This amount is equivalent to about 12% of the state's projected annual electricity demand by 2020 (the statewide forecasts in the below figure have changed somewhat, as discussed in Section II above, but the below figures are close enough for present purposes):

**Estimated Changes in Non-Renewable Energy Potentially Needed to Meet California Loads, 2008-2020**

| **California Electricity Supply** | **Annual GWh** | |
|---|---|---|
| Statewide Retail Sales, 2008, estimated [a] | 265,185 | |
| Statewide Retail Sales, 2020, forecast [a] | 308,070 | |
| Growth in Retail Sales, 2008-20 | 42,885 | |
| Growth in Net Energy for Load [b] | 46,316 | |
| **California Renewable Electricity** | **GWh @ 20% RPS** | **GWh @ 33% RPS** |
| Renewable Energy Requirements, 2020 [c] | 61,614 | 101,663 |
| Current Renewable Energy, 2008 | 29,174 | |
| Change in Renewable Energy between 2008 to 2020 [c] | 32,440 | 72,489 |
| Resulting Change in Non-Renewable Energy [d] | 13,876 | (-36,173) |

Source: Energy Commission staff

Notes:

a. Not including eight percent transmission and distribution losses

b. Based eight percent transmission and distribution losses, or 42,885 GWh x 0.08 = 46,316 GWh.

c. Renewable standards are calculated on retail sales and not on total generation, which accounts for eight percent transmission and distribution losses.

d. Based on net energy (including eight percent transmission and distribution losses), not based on retail sales.

As the GHG Analysis correctly describes, the broad trend that should occur as the state pushes toward the 33% by 2020 renewable mandate is an increasing retirement or curtailment of existing natural gas and coal-fired power plants. The state is currently at about 12% renewable energy, 1/8th of the total. This means that 20% or so <u>new</u> renewable energy generation will be added by 2020 (about 70,000 gigawatt hours), if the new mandate is met on time.

The CPUC's Renewable Portfolio Standard quarterly report from October of 2008 supports the GHG Analysis' conclusion that all new generation must be renewable (p. 10, emphasis added): "[I]f the state is required to generate 33% of its energy from renewable resources by 2020, then all new procurement of new energy resources between now and 2020 must be <u>entirely</u> renewable energy, except some new fossil for peaking capacity and to replace aging fossil plants <u>critical</u> to renewable integration." Accordingly, **the Commission must demonstrate that the CECP is "critical" for integrating higher levels of**

**renewable energy into the grid**. Neither the CAISO testimony nor the GHG Analysis comes close to meeting this exacting standard.

Moreover, new fossil fuel plants result in additional costs for ratepayers if the plants aren't used as planned, such as the many existing peaker plants in the San Diego region. The GHG Analysis lists the following power plants in the San Diego load pocket, most of which are peaker plants that run at extremely low capacity factors (4.1-111,112):

| Name | Capacity (MW) | 2008 Capacity Factor |
|---|---|---|
| Palomar Energy Center | **559** | **73.1%** |
| South Bay Power Plant (1-4) | **696** | **16.7%** |
| Encina Power Plant (1-5) | **951** | **12.0%** |
| Larkspur Energy LLC (1-2) | **90** | **8.0%** |
| CalPeak Power - Border | **50** | **3.4%** |
| CalPeak Power – Enterprise | **49** | **3.0%** |
| CalPeak Power – El Cajon | **49** | **2.8%** |
| Kearny (1-3D) | **127** | **0.4%** |
| MMC Chula Vista, LLC | **44** | **0.5%** |
| MMC Escondido, LLC | **44** | **0.4%** |
| Miramar (1A-1B) | **33** | **0.3%** |
| El Cajon | **13** | **0.6%** |
| South Bay Peaking Turbine | **13** | **0.5%** |

Encina Power Plant units 1-3, the units that will be retired if the CECP is constructed, had a combined capacity factor of 13.6% from 2002 to 2008.[19] All of the peaker plants that run at 3% or less constitute major costs for ratepayers because utilities must pay these power plant owners substantial fees whether they produce power or not. Every additional unnecessary fossil fuel peaker plant that is built adds to the costs of achieving California's renewable energy mandates. Even in the absence of renewable energy mandates, every unnecessary fossil fuel plant adds to ratepayer costs because costs are generally incurred by ratepayers even if the plants do not run.

Accordingly, California must retire or curtail fossil fuel generation plants, and not build new ones, while still maintaining grid reliability, in order to meet the 33% renewables by 2020 mandate. The GHG Analysis fails to demonstrate that the proposed CECP is "critical" for renewable energy integration. Such a

[19] GHG Analysis, 4.1-113, footnote 1.

determination cannot be made until additional statewide and local analyses from CAISO and the CTPG are completed.

### C. The CAISO testimony is incorrect regarding the peak power and integration value of solar PV

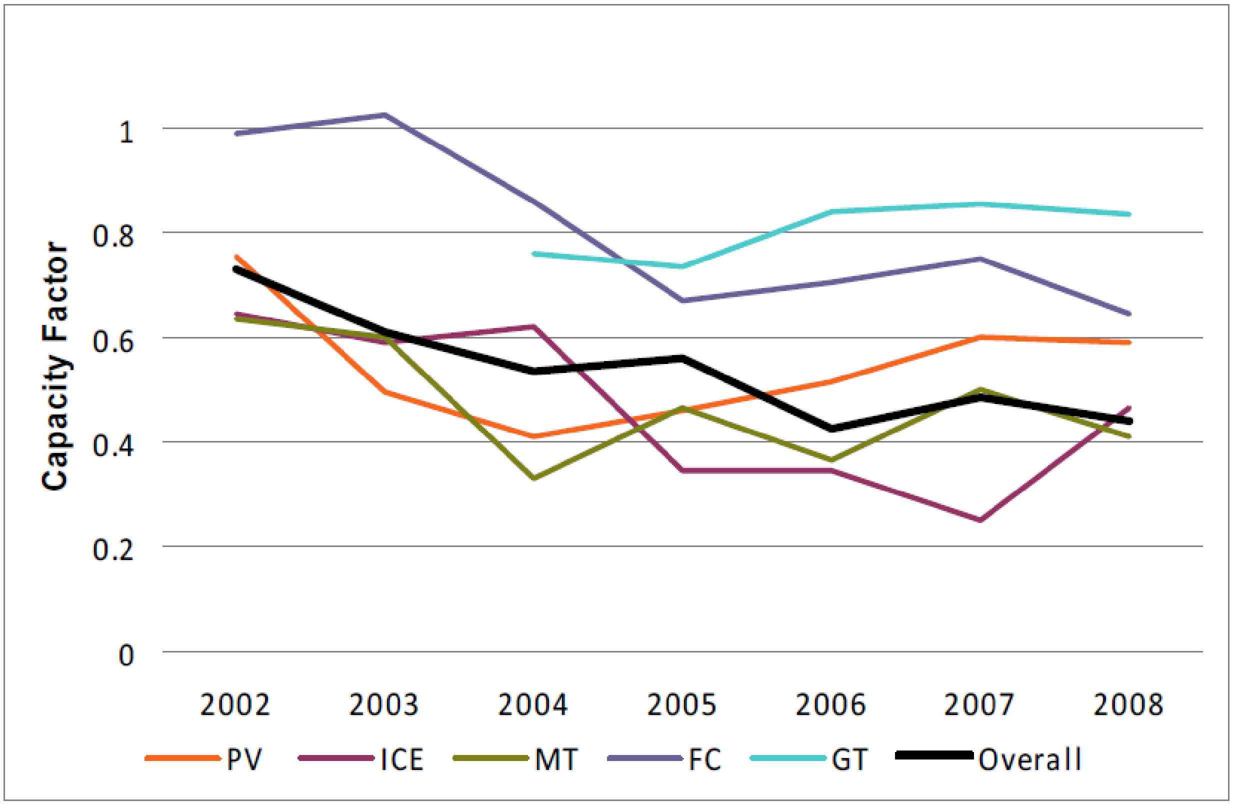
The CAISO testimony ignores the peak power value of solar PV, stating (p. 10): "Rooftop solar, both inside and adjacent to the San Diego area, is non-dispatchable and does not effectively assist in the integration of wind resources – unlike central solar with storage. As such, rooftop solar does not eliminate the need or reduce the value of flexible resources such as the proposed CECP that can ramp up and down and provide regulation services."

To demonstrate the inadequacy of this analysis, a detailed examination of the solar PV potential in the San Diego region, and its natural complementarity to wind power, is warranted.

#### 1. CSI and SDG&E solar PV programs

As described in the FSA, the California Solar Initiative incentivizes up to 3,000 megawatts of new solar installations by 2016. The expected proportion in the San Diego Region is 200 megawatts. This amount will not, by itself, obviate the need for the CECP. However, it helps substantially in reducing local peak demand because solar power is a reliable peak resource, with maximum power generation occurring in mid-afternoon, continuing into late afternoon, and occurring seasonally during summer and fall. A recent presentation[20] at the CPUC, as part of the SB 412 (Self-generation Incentive Program) proceeding, shows the peak power reliability benefits of solar PV to be quite high, at 60% in 2007 and 2008. This chart is entitled "CAISO Peak Hour Impact 2002 – 2008":

[20] Online at http://www.cpuc.ca.gov/NR/rdonlyres/0DF241E8-EE28-4754-8348-2CB76D0333A5/0/Presentation2SGIPImpacts.pdf.




Moreover, the CPUC has approved, or will soon approve, new wholesale distributed generation solar programs, administered by the utilities, based in large part on the peak power value of solar PV. Southern California Edison received CPUC approval for its 500 megawatt solar PV program in June of 2009. The CPUC decision, D.09-06-049, stated (p. 36, emphasis added):

> We find that the potential for building renewable projects on existing structures, thus minimizing environmental impacts, avoiding transmission upgrades, short-term cost reductions, program design that encourages technological improvements and the potential to deliver on-peak energy close to load are characteristics that set rooftop solar PV apart from other renewable technologies and make it unique.

SDG&E has a similar application pending, as the FSA notes (as does PG&E). SDG&E's program would result in an additional 52 megawatts of solar PV, a peak power resource, for a total under CSI and PV program of 252 megawatts, about half of the proposed capacity for the CECP.

There is, however, far more potential than this from solar PV on rooftops in the San Diego region. The CPUC recently completed an analysis of the state-wide potential for large rooftop PV, finding the technical potential for 604 megawatts in SDG&E territory, as shown in the following figure[21]:

**Total Statewide Large Rooftop Potential**

| | Large Roof Potential |
|---|---|
| PG&E | 2922 MWac |
| SCE | 5243 MWac |
| SDG&E | 604 MWac |
| Other | 2774 MWac |
| **Total** | **11,543 MWac** |

This 604 megawatt figure is, however, only the "technical potential," which assumes 100% participation by roof owners. This level of participation is not, of course, realistic, so a better analysis looks at "market potential," assuming that 50% of all roofs will participate by 2018-2020. This estimate is supported by the encouraging trends in solar installations, diminishing costs for solar PV, and the increasing interest at the local, state and federal level in easily deployable and environmentally-friendly tools for GHG mitigation, as well as by the fact that the CPUC analysis did not include parking lot solar potential. Parking lot solar potential is not merely a theoretical potential in the San Diego region: a 750 kW parking lot array is already installed at the Navy's North Island base and a 235 kW parking lot array at the Kyocera manufacturing plant.

In a similar proceeding, the Chula Vista Energy Upgrade Project, the Commission declined[22] to approve the Application for Certification because the FSA was inadequate in various ways. One area in which the Commission found the FSA inadequate concerned the analysis of the potential for solar PV to meet peak demand. The Commission stated (pp. 29-30):

> Bill Powers, P.E., an engineer with over 25 years of experience in the energy field, testified that it may be feasible to install PV on rooftops and over parking lots in a quantity sufficient to meet or exceed the project's incremental increase in output. (Ex. 616, pp. 11-14.) According to the FSA, rooftop PV would consume 4 acres per MW and for that reason is infeasible. (Ex. 200, p. 6-13.) We are unpersuaded by this evidence. Photovoltaic arrays mounted on

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[21] E3 and Black & Veatch analysis, online at http://www.cpuc.ca.gov/NR/rdonlyres/FBB0837D-5FFF-4101-9014-AF92228B9497/0/ReDECWorkshopPresentation1ExistingAnalyses.ppt.

[22] Final Commission Decision (June 2009), online at http://www.energy.ca.gov/2009publications/CEC-800-2009-001/CEC-800-2009-001-CMF.PDF.

> 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 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 compared with the cost of energy provided by PV. (Ex. 616, pp. 13 – 14.) In addition, while PV is not a quick-start technology which can be dispatched on ten minutes' notice any time of the day or night, 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.

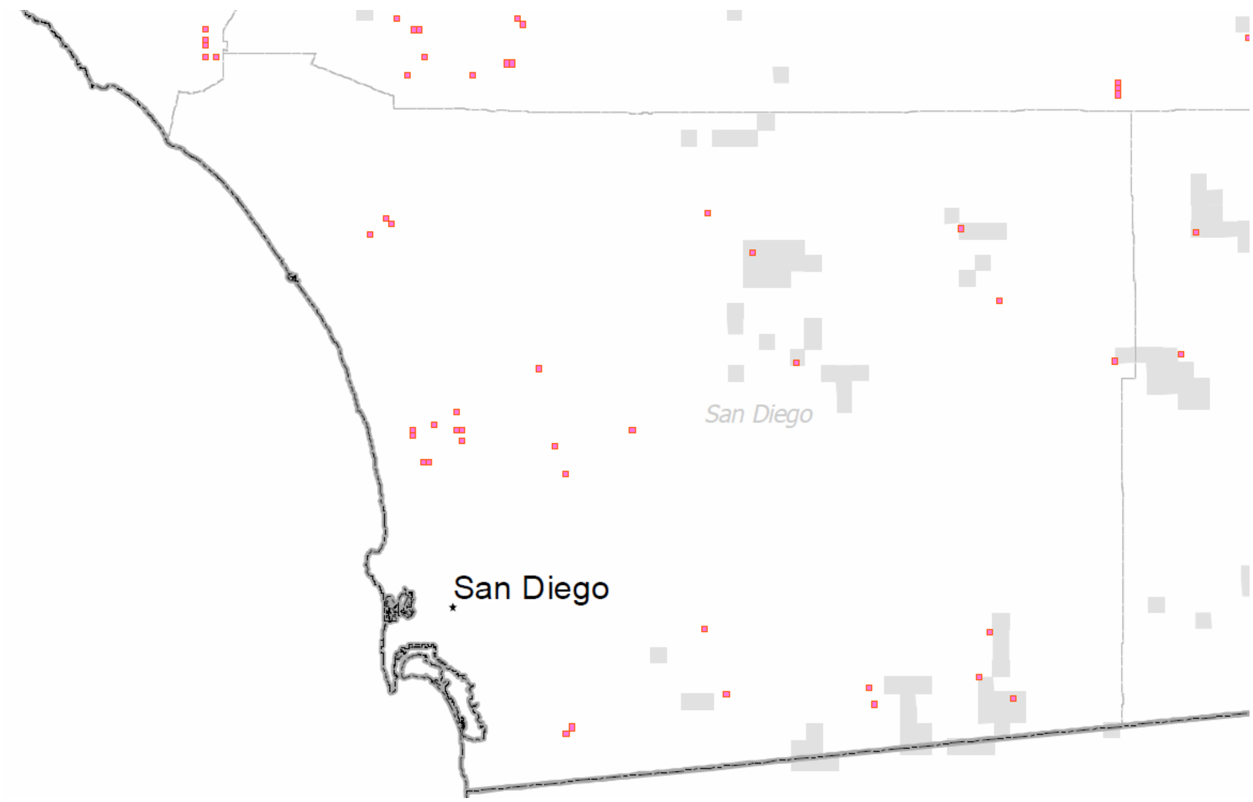
Therefore, the Commission itself has concluded, in a very similar case, that solar PV <u>may be</u> a peak power resource, a conclusion strongly supported by the SGIP program data showing a peak reliability factor of about 60% for solar PV, above.

Accordingly, when we sum the 200 megawatts expected from the CSI program and the 302 megawatt potential from SDG&E large rooftop potential (50% of 604 megawatts, which includes the 52 megawatts proposed for the SDG&E solar PV program), **we arrive at a total <u>market</u> potential of 502 megawatts of solar PV on large and small rooftops, almost equivalent to the proposed CECP.** As we shall see below, this is not, however, the entire analysis.

### 2. RETI and REDEC community-scale renewable energy ("wholesale distributed generation")

The CAISO analysis also ignores the potential for community-scale renewable energy facilities, also known as "wholesale distributed generation," to meet peak and mid-merit power demand. Wholesale distributed generation interconnects on the supply-side (instead of the customer side) of distribution lines and sub-stations. These facilities don't require any new transmission lines and can often be interconnected without any upgrades. The state-wide Renewable Energy Transmission Initiative (RETI), administered jointly by the Energy Commission and CPUC, found a huge potential (28,000 megawatts) for 20 megawatt solar PV facilities around the state, utilizing existing sub-stations and requiring no new transmission lines.[23] As ground-mounted systems, requiring about 160 acres each, these facilities can use tracking technology (generally not feasible for rooftop systems) that can increase power production by up to 40% when compared to a non-tracking solar system. So while ground-mounted systems will necessarily use open space for new power generation – with associated environmental impacts – the cost-effectiveness of such systems is dramatically improved in most situations because of the use of tracking technology.

RETI found 620 megawatts of technical potential from thirty-one 20 megawatt solar PV systems in San Diego County. However, the RETI analysis did not consider urban sites for community-scale solar PV projects, nor did it consider sites that could accommodate smaller projects, from 5-15 megawatts, for example. Accordingly, the total technical potential is actually far higher than the 620 megawatts. The below figure shows the potential for these 20 megawatt facilities in the San Diego region (each pink square is a potential 20 megawatt site):




The CPUC has, in its long-term procurement proceedings ("LTPP"),considered various scenarios for meeting forecasted power demand, and meeting state GHG

[23] RETI Phase 1A report, online at http://www.energy.ca.gov/2008publications/RETI-1000-2008-003/RETI-1000-2008-003-F.PDF

emission reduction and renewable energy mandates. The most recent LTPP is R.08-02-007. This proceeding, which is still underway, has been considering a "high distributed generation" scenario for meeting the 33% by 2020 RPS and I served as part of a working group examining this scenario during 2008 and 2009.

The CPUC recently convened a new group to follow up on the RETI wholesale distributed generation analysis, incorporating and expanding upon the analyses already completed in the LTPP. This group, the Renewable Distributed Energy Collaborative (ReDEC) met for the first time on December 9, 2009. **CPUC consultants E3 and Black & Veatch found 1,406 megawatts of total technical potential for solar PV in SDG&E territory, including 707 megawatts of ground-mounted solar PV**[24]:

**Installed Capacity by PV System Type (MWac)**

| Utility | Ground Mounted (> 30%) | Ground Mounted | Large Roofs | Small Roofs | Total |
|---|---|---|---|---|---|
| PG&E | 3,153 | 665 | 943 | 758 | **5,519** |
| SCE | 2,878 | 1,011 | 1,592 | 586 | **6,067** |
| SDG&E | 552 | 255 | 218 | 380 | **1,406** |
| Other | 2,417 | 335 | 1,057 | 500 | **4,309** |
| **Total** | **9,000** | **2,266** | **3,810** | **2,224** | **17,300** |

Applying the same 50% reduction applied above, to translate from technical to market potential by 2018-2020, we arrive at a total market potential of 703 megawatts from solar PV alone by 2018-2020, in SDG&E territory.

This analysis does not include, as mentioned, the potential for solar PV on parking lots; nor does it include the potential for wind or other renewable energy wholesale distributed generation throughout San Diego County. The CPUC consultants found an additional statewide technical potential of 1,054 megawatts of wind, biogas, biomass and geothermal wholesale distributed generation. Statewide renewable energy distributed energy technical potential (retail and wholesale) was calculated to be 18,355 megawatts, as shown in the following figure from the same presentation (this analysis does not include facilities larger than 20 megawatts, which are the focus of the utility Renewable Portfolio Standard programs):

[24] E3 and Black & Veatch analysis, online at http://www.cpuc.ca.gov/NR/rdonlyres/FBB0837D-5FFF-4101-9014-AF92228B9497/0/ReDECWorkshopPresentation1ExistingAnalyses.ppt.

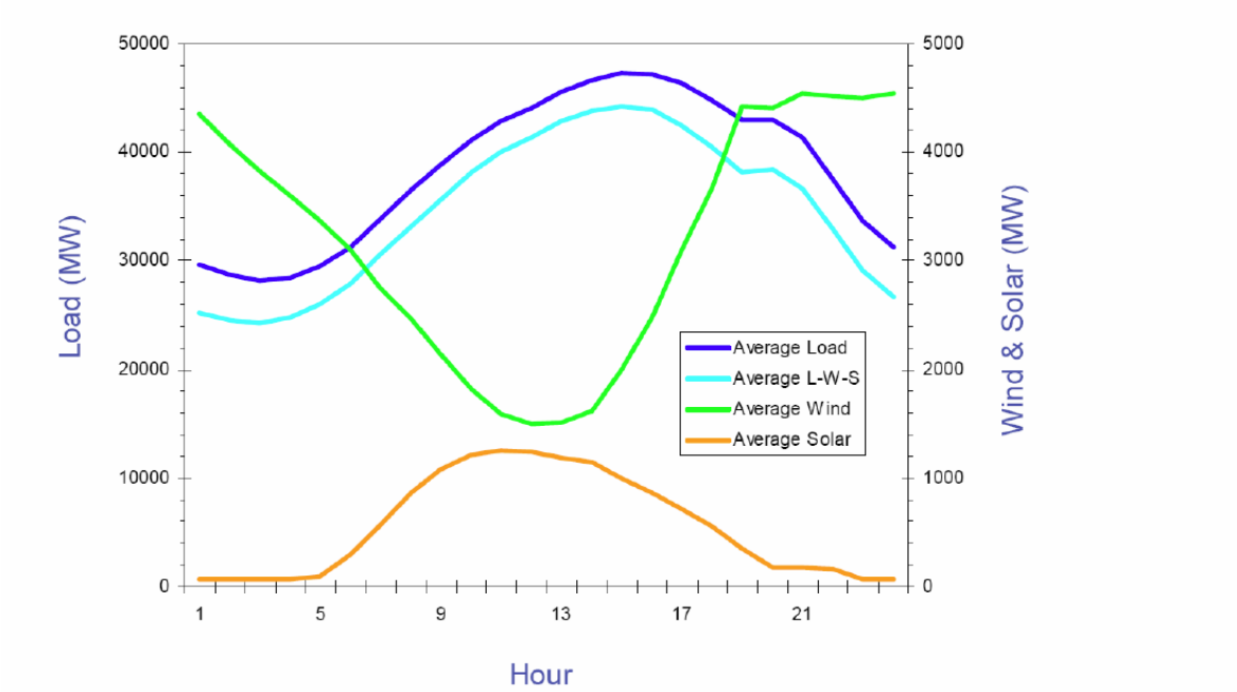
| Nameplate MW | DG Type | | | | | Total |
|---|---|---|---|---|---|---|
| Connection | Biogas | Biomass | Geothermal | Solar PV | Wind | |
| 1. Customer Site | - | - | - | 2,224 | - | 2,224 |
| 2. Feeder | 249 | 34 | - | 3,810 | - | 4,093 |
| 3. Distribution Bank | - | - | - | 2,267 | - | 2,267 |
| 4. Subtransmission | - | 128 | 175 | 9,000 | 468 | 9,771 |
| Total | 249 | 162 | 175 | 17,301 | 468 | 18,355 |

This analysis only looked at DG sites that require no new transmission lines or sub-stations and no upgrades to existing sub-stations (this is why the figure is lower than the initial RETI analysis, which did not consider whether upgrades would or would not be required).

### 3. Solar PV is a very good complement to wind power

Numerous analyses have found that solar power is a very good complement to wind power because solar power peaks in early to mid-afternoon and wind power generally peaks in the early evening and morning, as the following chart shows (MRW Report, p. 41):

**Figure 10: California Average Output of Wind and Solar, Load and Net Load, July 2003**




As such, solar PV in the San Diego region will, contrary to the CAISO testimony, be of substantial help in integrating wind power, in the San Diego region and potentially around the state.

An additional important note: the FSA's GHG Analysis describes the expected new generation facilities in the San Diego Basin, totaling 766 megawatts (from natural gas combined cycle, peaker, biomass and hydro storage facilities) "prior to 2013." (4.1-111) The GHG Analysis concludes that 396 megawatts of new generation will still be necessary to meet the CAISO local capacity requirements. Accordingly, the actual amount of reliable renewable energy peak generation required to establish that the CECP is not necessary is not the 558 megawatt proposed capacity of the CECP; rather, the actual amount is the 396 megawatts remaining after Encina and South Bay are retired and the proposed new plants (other than CECP) are constructed. As I have demonstrated above, there are more than enough renewable energy resources available, adjusted for market potential and peak capacity factor, to provide the local capacity requirements by 2018-2020.

In sum, even without the dip in forecast electricity demand resulting from the recession (see Section II), there is more than enough market potential for solar and other distributed generation technologies in SDG&E territory to meet the peak and mid-merit electricity demand that the proposed CECP would provide.

**Accordingly, McIntosh's testimony regarding the lack of peak power value from solar PV is demonstrably wrong in this instance. Solar PV has a substantial impact on peak demand and the San Diego load pocket has enough market potential for solar PV to more than meet the peak power capacity of the proposed CECP.**

### D. The CAISO testimony fails to demonstrate that the proposed CECP is necessary to meet local capacity requirements

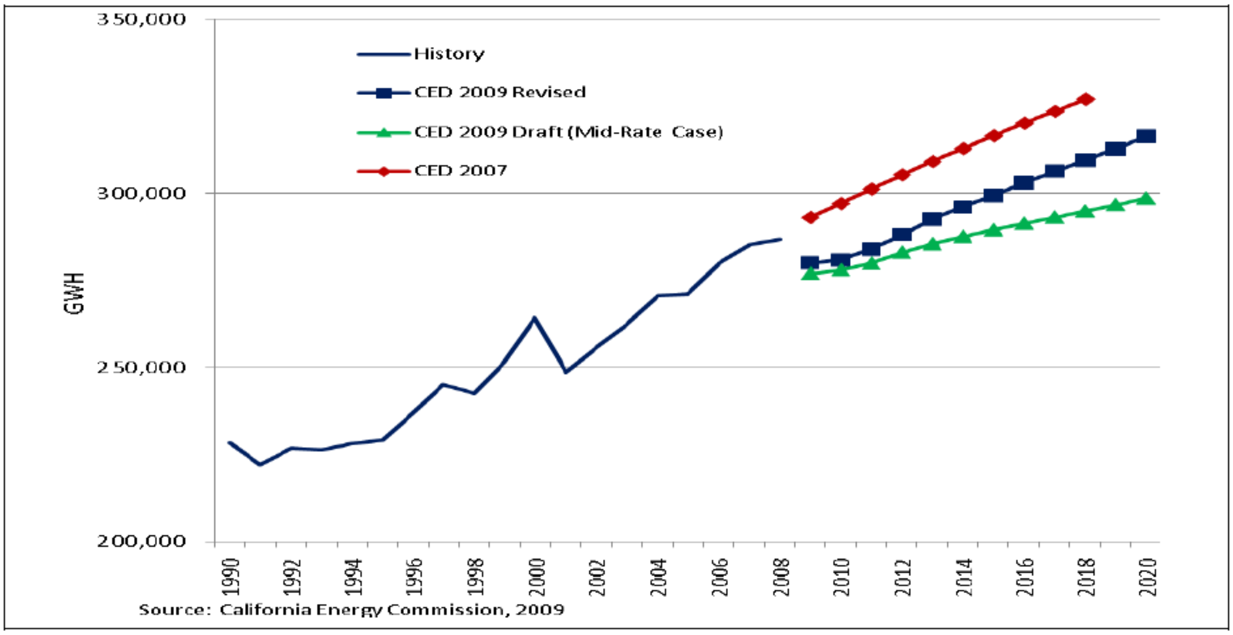
CAISO completed a study in 2008 ("CAISO 2008 study") relating to local capacity requirements (LCR), a subset of resource adequacy requirements. The McIntosh CAISO testimony does not, however, acknowledge this study, which is a major omission. The CAISO 2008 study concluded that LCR for the San Diego region were lower than in previous analyses because of the Sunrise Powerlink 230/500 kV transmission project, which has been approved and will ostensibly bring solar, geothermal and fossil fuel power from Imperial County to SDG&E territory.[25] The study found that LCR for the San Diego load pocket falls from 3,051 megawatts in 2009 to 2,418 megawatts by 2013 (pp. 1-2).

The CAISO testimony omits any mention of the dramatic change in electricity demand forecasts released in early December. The recession has significantly reduced demand growth forecasts, obviating the need for new fossil fuel

[25] CAISO, 2011-2013 LOCAL CAPACITY TECHNICAL ANALYSIS (2008), p. 3.

generation. The Energy Commission 2009 energy demand forecast ("CED 2009") states (p. 2): "Electricity consumption in *CED 2009 Adopted* is down by more than 5 percent and peak demand by almost 4 percent by 2018 compared to [the 2007 forecast]." This is a substantial difference and is illustrated in Figure 1 from CED 2009:

**Figure 1: Statewide Electricity Consumption**




Source: California Energy Commission, 2009

For comparison purposes, the proposed CECP would generate 2,297 GWh per year at a 47% capacity factor.[26] 2,297 GWh constitutes 0.74% of the CED 2009 forecast of 309,561 GWh annual electricity consumption by 2018. **With CED 2009 projecting a 5% reduction in electricity demand by 2018, this change alone obviates the need for more than six power plants the same size as the CECP.**

The CAISO testimony also ignores the fact that CAISO has authority to use non-RA power facilities to balance the grid and enjoys backstop authority to balance power demand within zones. (CPUC D.04-01-050, p. 11). Furthermore, the CAISO testimony states that the CAISO "expects the CECP would participate in the [CAISO's] ancillary services markets and provide regulation service," but makes no arguments as to why the CECP project is necessary for a successful ancillary services market in light of the new Market Redesign and Technology Update – which came online in early 2009 – day-ahead market more generally.

[26] This is the capacity factor the Application for Certification seeks, though in actuality the CECP will probably have a capacity factor lower than this.

In sum, the CED 2009 forecast described above significantly reduced the electricity demand forecast for California, obviating the need for about six power plants the size of the proposed CECP. The 2008 CAISO study has not been updated in light of this reduced demand forecast. Section II.C also described in detail the ability of solar PV, both retail and wholesale distributed generation, to meet the peak demand requirements of the San Diego load pocket even without this reduction in demand.

**Accordingly, the McIntosh CAISO testimony fails to make the case that the proposed CECP is necessary to foster integration of renewables or to meet local capacity requirements.**

## III. Conclusion

The CAISO testimony and the related FSA GHG Analysis fail to provide the necessary analysis to support important assertions. More analysis is necessary and is underway as part of at least three major state-wide efforts that are highly relevant to the proposed CECP. Without completing an analysis specific to the CECP, the environmental analysis of the CECP is incomplete and inadequate.

Tam Hunt, J.D.

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