**BEFORE THE**
**PUBLIC UTILITIES COMMISSION**
**OF THE**
**STATE OF CALIFORNIA**

| | | |
|---|---|---|
| Order Instituting Rulemaking to Develop Additional Methods to Implement the California Renewables Portfolio Standard Program | ) ) ) ) | Rulemaking: 06-02-012 (Filed February 16, 2006) |

# Post-Workshop Opening Comments of the California Wind Energy Association, the California Cogeneration Council, the Large-scale Solar Association, and the Solar Alliance

R. Thomas Beach
Patrick G. McGuire
*Crossborder Energy*
2560 Ninth Street, Suite 213A
Berkeley, California 94710
Telephone: 510-549-6922
Facsimile: 510-649-9793
E-mail: tomb@crossborderenergy.com

On Behalf of
**CALIFORNIA WIND ENERGY ASSOCIATION,**
**CALIFORNIA COGENERATION COUNCIL,**
**LARGE-SCALE SOLAR ASSOCIATION, and**
**THE SOLAR ALLIANCE**

June 6, 2008

# Table of Contents

**BEFORE THE**
**PUBLIC UTILITIES COMMISSION**
**OF THE**
**STATE OF CALIFORNIA**

| | | |
|---|---|---|
| Order Instituting Rulemaking to Develop Additional Methods to Implement the California Renewables Portfolio Standard Program | ) ) ) ) | Rulemaking: 06-02-012 (Filed February 16, 2006) |

# Post-Workshop Opening Comments of the California Wind Energy Association, the California Cogeneration Council, the Large-scale Solar Association, and the Solar Alliance

The California Wind Energy Association (CalWEA), the California Cogeneration Council (CCC), the Large-scale Solar Association (LSA),[1] and the Solar Alliance (SA) are pleased to present these post-workshop opening comments on issues associated with the 2008 market price referent (2008 MPR), as requested in Administrative Law Judge Anne Simon's Ruling dated May 20, 2008 (May 20 ALJ Ruling) in the above-captioned proceeding. CalWEA, CCC, LSA, and SA all have participated actively in this phase of R. 06-02-012 on matters concerning the 2008 MPR, including filing pre-workshop proposals and participating in the workshop that the Commission's Energy Division conducted on March 27, 2008. These parties generally share the same positions on issues concerning the 2008 MPR, and are filing jointly in response to the ALJ's encouragement for parties that have similar positions to do so.

[1] The companies that comprise the LSA have participated in earlier phases of this proceeding as the Concentrated Solar Power (CSP) companies. The members of LSA include Abengoa Solar, Ausra, Brightsource, and Solel. All of these companies are actively involved in developing solar generation projects for the California market and the state's Renewables Portfolio Standard (RPS) program.

CalWEA, CCC, and several of LSA's member companies filed joint pre-workshop comments on 2008 MPR issues on March 6, 2008; Solar Alliance filed separate pre-workshop comments. Those comments set forth in detail our proposals for the necessary changes that the Commission should direct in the calculation of the 2008 MPR. These post-workshop comments will focus on the issues debated at the workshop, and in particular respond to the questions posed in the May 20 ALJ Ruling.[2]

## 2. PROPOSED CHANGES TO THE 2008 MPR

CalWEA / CCC / CSP summarize in **Table 1** their recommended changes to the 2008 MPR calculation, compared to the input values and calculation methods used for the 2007 MPR.

**Table 1:** *CalWEA / CCC / CSP Proposed Changes to the 2008 MPR*

| Input Value / Calculation Method | 2007 MPR | Proposed 2008 MPR |
|---|---|---|
| CCGT Capital Cost ($/kW) | $1,053 per kW | $1,300 per kW |
| CCGT Capital Cost Escalation | ends in 2010 | ends in 2013 |
| CCGT Capacity Factor (%) | 76% | 68% |
| MPR Line Loss Factor | 0.985 | 0.969 |
| Fuel Price Risk Premium (after NYMEX data ends) | none | Apply the forward price premium in the last 5 years of NYMEX futures prices to the fundamentals forecast in Year 13 and beyond. |
| GHG Emissions Cost | $8 per ton in 2004<br>5% escalation per year | $29 per ton CO2 in 2008,<br>$36 per ton CO2 in 2020,<br>$65 per ton CO2 in 2030 |

[2] The numbering of the sections in these comments corresponds to the numbering in the May 20 ALJ Ruling.

We have provided to the Energy Division and posted on CalWEA's website[3] a revised version of the MPR model that includes the changes proposed above for the 2008 MPR. We have highlighted these changes in the model in yellow, so the reviewer can understand them clearly. This model also includes a revised natural gas price forecast that uses NYMEX forward prices for the month ending May 12, 2008.

## 3.1 MPR NON-GAS METHODOLOGY AND INPUTS

### 3.1.1 Installed Capital Costs

- Should the cost cap approved by the Commission for PG&E's development of the Colusa CCGT power plant be added to the data set used to calculate MPR installed capital costs? If not, why not?

The Commission should not use the cost cap approved for the Colusa CCGT power plant in the MPR data set of installed CCGT capital costs. PG&E acquired the Colusa plant from a developer that was unable to complete the plant under the terms of its contract with PG&E. The terms of PG&E' acquisition of the project are confidential, and it is not known exactly what value PG&E obtained in the transaction, or what it paid for that value.[4] PG&E clearly obtained a project that already was under development – for example, the Colusa project was in the middle of its certification case before the California Energy Commission (CEC).[5]

Past decisions on the MPR methodology have established clearly that data from the sale

---

[3] http://www.calwea.org/publicFilings.html.

[4] Several of the parties to A. 07-11-009, PG&E's application for approval of a certificate of public convenience and necessity (CPCN) for Colusa, argued that the Commission should not approve PG&E's acquisition without knowing the details of the considerations received by each party to the transaction. The Commission denied this request in D. 08-02-019, on the grounds that the details of the transaction will not impact the ratepayers' cost for the project. *See* D. 08-02-019, at 5-6.

[5] Colusa filed its AFC at the CEC in November 2006 (CEC Docket No. 06-AFC-9). *See,* also, D. 08-02-019, at 7-8.

of "distressed" or partially-completed power plants should not be used to set the MPR, unless there is significant data available on the exact considerations received by each side to the sale of such a project:

> We agree with TURN, PG&E, and the CalWEA group that the Commission should be cautious about using data from "secondary market" sales of distressed, bankrupt, and/or partially completed projects. Such transactions can have significant unknowns. If, for example, the sale was just a portion of a much larger deal (such as PG&E's acquisition of the Contra Costa 8 unit as part of a settlement of litigation in the Mirant bankruptcy case), were there trade-offs in the price of the CCGT in exchange for other considerations? Therefore, we adopt the CalWEA group's recommendation that the sales prices in such transactions be examined carefully and adjusted where necessary to account for such considerations. Unless adequate data are available to serve as the benchmark for such deals, *e.g.*, through the record in a litigated Commission proceeding, then data on secondary market transactions should not be used to set the MPR. However, we also agree with SCE that a project that changes hands only before it becomes operational can be used, with certain limitations, in the MPR calculation.[6]

Given that detailed information is not available on the consideration that PG&E gave or received in its acquisition of Colusa, the Commission should not rely on the cost cap for this project as a data point for the installed capital costs used in the 2008 MPR.

- Discuss strengths and weaknesses of using installed capital costs identified in the CEC's Cost of Generation (COG) report.[7] To what extent does the COG report accurately reflect historic capital cost data?

The CCGT installed capital cost assumptions stated in this CEC report should not be used as inputs to the 2008 MPR. The CCGT capital costs cited in this report are based on surveys of CCGT plants that went into service from 2001 - 2006, as shown in Table 11 of the report. However, as verified at the workshop by Joel Klein of the CEC (the report's principal author),

---

[6] D. 05-12-042, at 26-27 (emphasis added).

[7] "Comparative Costs of California Central Station Electricity Generation Technologies" (December 2007); hereafter, *2007 Comparative Generation Cost Report.* This CEC report is available at http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SF.PDF.

the CEC simply escalated these 2001 - 2006 plant costs to 2007$ using standard inflation indices, which do not capture the spike in power plant construction costs that began in 2006.[8]

- To what extent should the CCGT inputs and assumptions of the CEC's "Comparative Costs of California Central Station Electricity Generation Technologies" report (issued in December 2007) be used to update the MPR inputs and assumptions for 2008 and later years? Please specifically identify each input or assumption and provide a specific justification for the use of each for the MPR.

CalWEA / CCC / LSA / SA do not oppose the use of the other CCGT operating and cost parameters contained in the *2007 Comparative Generation Cost Report.* Generally, these other parameters appear to be representative of the class of CCGTs that have been and are continuing to be installed in California. Thus, the Commission can use the CEC's data for such CCGT cost and operating parameters as

- Fixed O&M
- Variable O&M
- Heat rate

### 3.1.2 Capital Cost Escalation Rate

- Should the MPR methodology adopt a rolling five-year time frame for capital cost escalation, *e.g.*, the 2008 MPR would escalate capital costs through 2013; the 2009 MPR would escalate capital costs through 2014; etc.? If not, what assumptions should be made for capital cost escalation after 2010?

D. 05-12-042 affirmed a convention, proposed by PG&E, that the CCGT capital costs would be escalated for five years after the initial year of the MPR period.[9] Then escalation would

---

[8] *2007 Comparative Generation Cost Report*, at 51, 58, and C-2. Page C-2 shows the CEC's response to a PG&E comment suggesting that the CEC should use construction cost indices instead of general inflation indices to escalate capital costs. Inspection of the CEC's spreadsheet model also verifies the CEC's use of standard GDP inflation indices. The escalation in capital costs is at cell G2 of the "Data 2" tab for combined-cycle costs.

[9] D. 05-12-042, at 43-44.

stop, in recognition that technological improvements could result in lower future power plant costs. As a result, the 2005 MPR stopped escalating CCGT capital costs in 2010. However, the 2006 and 2007 MPRs also stopped the escalation of capital costs in 2010. It is clear today that the CCGTs that are being installed for service in 2010 (e.g. the Colusa project) are little different than the CCGTs that have been built in California in the 2000s. For example, most continue to use General Electric Frame 7F turbines or their equivalent. As a result, with no significant improvements in CCGT technology on the horizon, it would be logical to resume a five-year escalation in CCGT capital costs, i.e. through 2013 in conjunction with the 2008 MPR, through 2014 with the 2009 MPR, etc.[10] There appeared to be significant agreement on this point at the workshop.

- Do you agree with SCE that the current MPR methodology, which utilizes capital costs from two plants completed in 2006, fully reflects recent increases in CCGT materials and construction costs?

- If not, how should the MPR methodology be modified to more accurately reflect recent capital cost increases? Proposals should identify the assumed calendar year for the date of the estimate; in what year's dollars the costs should be expressed; and how cost indices should be applied.

- Can the Brattle Report be used to accurately update the historic MPR capital cost calculation to reflect recent market data for CCGT materials and construction costs? If so, include a proposal for how information from the Brattle Report should be implemented in the MPR methodology and a modified MPR model.

There was little debate at the workshop on the general point that power plant construction costs escalated very sharply in 2006 - 2007, and that this increase is greater than is reflected in the U.S. Army Corps of Engineers (USACoE) indices used in the MPR model. The studies by both the Brattle Group and Cambridge Energy Research Associates, cited in the opening comments of CalWEA / CCC / CSP, describe these extraordinary increases. Only Edison appears to oppose the idea that the historic escalation rates in the MPR model should be adjusted

[10] Consistent with D. 05-12-042 (page 31), parties aware of the significant use of new CCGT technology in California could ask the Commission to change the technology assumed in the MPR.

upwards. Edison's position is completely undercut by its own experience building four 45 MW combustion turbine peakers in southern California in 2006 - 2007. The initial cost estimate in the fall of 2006 for these units was $50 million per unit ($1,111 per kW). The units went into service in August 2007. On December 31, 2007, Edison filed for cost recovery for these four plants; their final cost will be $262 million ($1,456 per kW), a 31% increase from the initial September 2006 estimate.[11] In contrast, the current MPR model uses USACoE escalation factors of 5.69% for 2006 and 3.74% for 2007.

CalWEA / CCC / LSA / SA have three suggestions for improving the historic cost escalation assumptions in the MPR model. The first is to use the escalation rate in the Brattle study for 2006, instead of the escalation resulting from the USCoE index. This calculation is shown in Table 2 of the CalWEA / CCC / CSP opening comments, and results in a 2008 MPR capital cost of $1,361 per kW. The second approach would be to use the Handy Whitman power plant cost indices for 2006 - 2007 that the PJM Interconnection used in its January 2008 update of CT costs, a study which PG&E cited in its pre-workshop comments.[12] In this study, PJM chose to use Handy-Whitman indices showing 10% annual cost increases over the last two years (2006 and 2007). Replacing the USACoE indices for 2006 and 2007 with 10% each year produces a 2008 MPR capital cost of $1,240 per kW. We recommend a third alternative of averaging the results of these two sets of indices, resulting in an installed capital cost of $1,300 per kW.

- What are the strengths and weaknesses of using private reports such as the Handy-Whitman or CERA indices, as compared to publicly available resources such as the U.S. Army Corps of Engineers' Engineering and Design Civil Works Construction Cost Index System or the Energy Information Administration's (EIA) 2007 Annual Energy Outlook?

---

[11] See A. 07-12-029 (Edison's application for recovery of its peaker costs), at pages 2-3. Edison's initial 2006 cost estimate of about $50 million per peaker is cited in A. 07-12-029, SCE Testimony, at 27.

[12] PG&E Pre-workshop Comments, at page 5, footnote 2. A copy of this PJM study is Attachment A to this filing. See the Handy Whitman indices in Table 4 on page 9.

Specialized, private inflation indices have been used by the Commission and the utilities that it regulates for many years. We would be very surprised if the Commission did not already subscribe to Handy Whitman's set of utility cost indices. Private indices have to prove their worth in the marketplace; otherwise, they will fail to gain subscribers. In our experience, private forecasters tend to respond more quickly to emerging trends than do government surveys. The Brattle Report, at pages 27 - 29, includes a detailed critique of the Energy Information Administration's (EIA) recent power plant cost estimates, and notes that EIA has admitted that it has been slow to reflect the recent sharp jumps in the costs of construction commodities.

### 3.1.3 Capacity Factor

#### 3.1.3.1 Revenue Assumptions

- Discuss whether a levelized fixed price adjusted by TOU factors or a day-ahead spot market price is the more appropriate and reasonable assumption for calculating a market based, long-term fixed price for the MPR.

The prices that renewable generators bid to the IOUs in RPS solicitations are fixed, levelized, all-in (energy and capacity) prices for terms of 10-, 15-, 20-, or more years. Therefore, it is appropriate that the MPR also should be an all-in price levelized over similar terms. Thus, the MPR model appropriately calculates the all-in costs of a CCGT levelized over 10-, 15-, or 20-years. The MPR is not a day-ahead spot market price; it is the long-term market price for a resource that provides both energy and capacity.

Each IOU applies time-of-use (TOU) factors to the bid prices from RPS generators, so that generators receive a price signal as to the relative value of power in the various TOU periods. As RPS generators bid all-in prices, the TOU factors should reflect the relative value of both energy and capacity in each TOU period. We do not know whether the IOUs' different sets of TOU factors accomplish this because, as noted in the next question, the IOUs will not reveal how their TOU factors are calculated, and the Commission has not required them to "benchmark" their TOU factors since 2005. The Commission presently allows each utility to propose its own set of TOU factors in its RPS Request for Offers (RFOs); these also are the TOU

factors used in the MPR model. What we do know is that SDG&E's RPS TOU factors are energy-only, so SDG&E's TOU factors, when applied to the MPR, do not produce an accurate profile of all-in market prices.

- The IOUs' TOD factors rely on proprietary methodologies and assumptions that are not necessarily consistent with those used for the proxy CCGT. PG&E's and SCE's TOD factors are based on energy and capacity, while SDG&E's TOD factors are for energy only. Please discuss the relative significance of these inconsistencies and how these concerns may be addressed in the 2008 MPR.

Today, the RPS TOU factors are used in the MPR model for only one purpose: to estimate the capacity factor of the CCGT. When the MPR is multiplied by a set of TOU factors, the result is assumed to represent a time-varying profile of all-in market prices. The CCGT is assumed to operate in those TOU periods when the profiled market price is higher than the CCGT's variable running costs. However, as documented in Table 3 of the CalWEA / CCC / CSP opening comments, this method has produced CCGT capacity factors that vary significantly from year-to-year and between the IOUs, even though the IOUs operate in the same or closely-linked wholesale markets. This variation is not surprising, because the IOUs' sets of TOU factors are very different, for unknown reasons. SDG&E's TOU factors are not even all-in factors. Because SDG&E's factors do not include capacity, the MPR model using SDG&E's TOU factors consistently predicts that a CCGT would run at its maximum technical capacity factor of 92%. Generally, the existing method has produced CCGT capacity factors that are higher than actual CCGT capacity factors observed in the California market.

These problems argue strongly for a new, more stable, more realistic approach to calculating the CCGT capacity factor.

#### 3.1.3.2. Parties' Capacity Factor Proposals

CalWEA / CCC / LSA / SA propose a simple method for determining the CCGT capacity factor, a method that is fully consistent with the fundamental purpose of the MPR. Before we

describe that proposal, it is important to review the role of CCGT costs in setting the MPR.

In D. 03-06-071, the Commission decided to implement P.U. Code Section 399.15(c) through the use of the costs of a new generating plant as a proxy for the long-rum market price of electricity.[13] The Commission chose a CCGT for the baseload MPR, and a CT for the peaking MPR. Under this construct, the "system average" MPR over all hours was a combination of the peaking MPR in peak hours plus the baseload MPR in all other hours. Obviously, this "system average" MPR would have an average cost over all hours that was higher than the baseload MPR. The Commission used the maximum "technical" capacity factor for a CCGT (92%) to set the baseload MPR in the 2004 MPR.[14]

In D. 05-12-042, the Commission made a significant change to this construct.[15] The Commission eliminated the peaking MPR, and adopted the use of the time-differentiated all-in costs of a CCGT to set the MPR for generators with a variety of operating profiles. Because TOU factors equal 1.0 when averaged over all hours of the year, after D. 05-12-042 the average of the MPR price over all hours of the year equaled the all-in costs of a CCGT. In making this change, the Commission changed the role of the CCGT, from the proxy for a baseload resource to the proxy for the system average resource. The CCGT no longer was assumed to operate only in a baseload, "always on" fashion. In making this change, the Commission correctly recognized that it was no longer appropriate to use the maximum, technical capacity factor, given the new role for the CCGT. Instead, the Commission attempted to adopt a method that would estimate a realistic, market-based capacity factor for CCGTs in California. This change was appropriate given the new role of time-differentiated CCGT costs as the proxy for multiple types of generation products.

---

[13] D. 03-06-071, at 15-19.

[14] D. 05-12-042, at 32.

[15] See the discussion in this order at 32-34.

A CCGT is the logical choice for this role as the system average resource: in California, CCGTs fill the role of intermediate-load plants. They operate at capacity factors of 60% to 70%. At times, the marginal resource can be either less expensive or more expensive than the variable costs of a CCGT. CCGTs do not operate off-peak, when cheaper power is available. In peak periods, CCGTs are not the marginal resource, as CT peakers and older conventional steam plants with higher heat rates are on the margin. As Mr. Beach illustrated in the exhibit that he distributed at the workshop, and which is reproduced here as **Table 2**, if one uses representative all-in costs and capacity factors for CTs on-peak, CCGTs as the intermediate resource, and market power in the remaining off-peak hours, the system average cost is very close to the all-in CCGT cost at a 60% capacity factor. If one used the CCGT's cost with a 92% capacity factor in this calculation, as TURN proposes, the all-in CCGT cost would underestimate the system average cost.

**Table 2:** *Illustrative, All-in Cost of Marginal Market Resources*

| Type | Resource | % on Margin | Cost per MWh | Sources |
|---|---|---|---|---|
| Peak | CT | 5% | $468 | 2007 CEC *Comparative Generation Cost Report*, Tables 4 and 6 |
| Intermediate | CCGT | 55% | $94 | 2007 CEC *Comparative Generation Cost Report*, Tables 4 and 6 |
| Off-Peak | Market Energy | 40% | $47 | 2007 average Dow Jones NP-15 / SP-15 off-peak price |
| Total / Weighted Average | | 100% | $94 | |

The IOUs' inconsistent sets of RPS TOU factors show the difficulty of estimating all-in TOU factors in the California market. This difficulty is not surprising, given the lack of a visible capacity market in California. However, the state does have a visible and functioning wholesale energy market, and CCGTs are dispatched on the basis of these prices. Accordingly, the CalWEA / CCC / LSA / SA proposal is simply to use NP-15 and SP-15 market prices to calculate a realistic CCGT capacity factor.

We have suggested two ways to do this. The first way is simply to rely on the California

Independent System Operator (CAISO), which each year presents in its annual report a calculation of the capacity factor of a CCGT, based on wholesale market prices from the prior year.[16] The CAISO's calculated CCGT capacity factors have been quite stable over the 2003 - 2007 period, as shown in **Table 3**.

**Table 3:** *CAISO Calculated Capacity Factors for New CCGTs*

| Year | NP-15 | SP-15 | CA Average |
|---|---|---|---|
| 2004 | 69% | 72% | 71% |
| 2005 | 65% | 72% | 69% |
| 2006 | 63% | 75% | 69% |
| 2007 | 69% | 76% | 73% |
| **Average** | | | **70%** |

Source: Excerpted from Table 2.9 of Chapter 2 of the 2007 CAISO Annual Report, at www.caiso.com/1f9c/1f9c8cf421530.pdf

The NP-15 capacity factors have ranged from 63% to 69% and the SP-15 capacity factors have varied from 72% to 76%. The calculated statewide average CCGT capacity factor over the period is 70%.[17]

The second way is to calculate the CCGT capacity factor directly, based on daily NP-15 and SP-15 market prices, daily natural gas prices, and the MPR's CCGT operating parameters (heat rate and variable O&M).[18] We have provided Energy Division with this calculation for 2007, which results in CCGT capacity factors for 2007 of 65% for NP-15 and 71% for SP-15,

---

[16] For example, *see* CAISO, *2007 Annual Report on Market Issues and Performance*, at Chapter 2. This report is available at www.caiso.com/1f9c/1f9c8cf421530.pdf.

[17] *Ibid.*, at pages 2.51-2.56 and Table 2.11. The CAISO analysts assume that the CCGT dispatcher has perfect foreknowledge of the next day's prices in both the bilateral day-ahead wholesale market and the CAISO's real-time market; thus, the CAISO admits that its calculations of CCGT market revenues represent the "upper limits of potential revenues" (and presumably of CCGT capacity factors) in the California market.

[18] We have used a CCGT heat rate of 6,917 Btu per kWh and a variable O&M cost of $2.48 per MWh, both from the 2007 MPR model.

with a statewide average of 68%. To be consistent with the MPR model, we have used a CCGT heat rate and variable O&M costs from the 2007 MPR (the heat rates and variable O&M assumed by the CAISO in their calculations were slightly different). A CCGT capacity factor of 68% is our recommendation for the 2008 MPR. The CAISO calculations and our work are very similar, and produce consistent, stable results over time.

The CalWEA / CCC / LSA / SA proposal has the following attributes:

- It models the operating decisions likely to be made by a CCGT facing contractual terms and market conditions assumed for the MPR CCGT proxy. A CCGT, even it has a fixed price contract, will not operate if the short-term market price is less than its operating costs, because the operator can simply substitute less expensive market power for his plant's output.

- This method results in a reasonable level of operation relative to CCGT plant characteristics and actual CCGTs operating in the market, because it accurately reflects the dispatch comparison between short-term market prices and the variable operating costs of the proxy CCGT.

- The method provides adequate revenue to ensure that a new CCGT will recover its full costs under a range of future price and market conditions. Edison and TURN have criticized our proposal (and the current method, as well) on the grounds that the time-differentiated MPR, using a realistic CCGT capacity factor, results in a stream of prices that over-recovers the CCGT's fixed costs over the hours that the CCGT operates. In fact, Edison has proposed to adjust the capacity factor such that the CCGT recovers exactly its costs over the hours that it is assumed to operate, using the time-differentiated profile of the MPR.[19] This assumes that the CCGT is compensated based on the full

[19] We also note that the time-differentiated MPR is below the CCGT's variable costs in off-peak hours, such that the average MPR price over all hours exactly equals the CCGT's all-in

marginal, all-in price in all hours. In reality, this is not the case: there is no actual market in California that pays the marginal all-in price in all hours. The only functioning market at this time is a short-term wholesale energy market. As a result, a CCGT will be compensated for at least a portion of its fixed costs through a contract with a load-serving entity. Competition with other CCGTs for such contracts is likely to restrict the CCGT's cost recovery to no more than its costs. Thus, the claims of TURN and SCE that the current MPR method somehow "over-recovers" the fixed costs of a CCGT are a red herring.

- Given the time-differentiated profile of the MPR, it is not unexpected that there appears to be a problem of over- or under-compensation in some periods. However, this is not a significant problem that impacts the MPR values and administration of the RPS, provided that the average price, over all hours, equals the all-in costs of a CCGT under realistic operating conditions in the California market. That is how the methodology has worked since D. 05-12-042; the only refinement that is needed today is to use a simpler and more transparent method to calculate a realistic capacity factor for the CCGT. This is accomplished with the CalWEA / CCC / LSA / SA proposal.

#### 3.1.4. Transmission and Line Losses

- Comment on CalWEA's proposal to use a generation-weighted average to calculate a statewide GMM value, as compared to the current methodology, which uses a simple system average.
- Comment on SCE's proposal that the MPR methodology be modified to reflect delivery at the busbar, rather than the current methodology which assumes delivery at the load center. SCE argues that a CCGT typically delivers at the busbar.

The current MPR model uses a CAISO generation meter multiplier (GMM) of 0.985 as the measure of average line losses on the CAISO system; this GMM is equivalent to 1.5% transmission line losses. This line loss factor is taken from the QF line loss formula adopted in

---

costs.

D. 01-01-007. However, actual CAISO system average transmission lines losses are 3.1%.[20]

The current use of the simple average GMM is simply an error. The simple average GMM is not weighted by the amount of power that is produced by each generator for which the CAISO calculates a GMM. The use of a simple average GMM weights all generators equally, regardless of size, so a 5 MW QF in the load center is assumed to have the same impact on overall losses as a 2,200 MW, remote generator such as Diablo Canyon. By number, most generators are relatively close to the load centers (and thus have GMMs close to 1.0). Thus, the use of the simple average GMM understates the contribution to line losses from large, remotely-located generators (such as Diablo Canyon, much of the state's hydro power system, and the large interties that import power into the state), and understates system average transmission losses on the CAISO grid. The use of a correct, generation-weighted average GMM would reduce the system average GMM to 0.969, corresponding to the actual 3.1% average losses on the CAISO transmission grid. This clear error should be corrected in the 2008 MPR model.

Edison has raised the more fundamental issue of whether the MPR price should be calculated at the busbar or at the load center. The MPR should be calculated at the load center, so that all renewable projects are compared to the MPR on an equivalent basis from the perspective of location on the transmission grid. For example, consider two renewable projects: Project A is located relatively close to the load center, with 1% line losses to reach the load center; Project B is sited more remotely, with 5% line losses to the load center. Assume system average losses are 3%. Both projects bid the same price at the busbar, equal to 100% of the MPR before the adjustment for line losses. If the MPR is assessed at the busbar, both projects would be deemed to be at the MPR price. However, at the load center, the cost of Project A's power is 2% below the MPR, while Project B's power is 2% above the MPR. This is a more accurate assessment of the relative impacts of these projects on ratepayers. In particular, the use of an

[20] CAISO Oasis data for each month in 2007 are shown in Table 4 of the CalWEA / CCC / CSP pre-workshop comments. This CAISO data compares total system losses to actual system loads. See http://oasis.caiso.com/.

MPR at the busbar could result in a significant subsidy of out-of-state renewables whose power will incur significant line losses to reach California. Finally, an MPR calculated at the load center is required for consistency with how renewable generators are paid under typical RPS contracts. RPS contracts pay renewable generators for their generation adjusted by their site-specific GMM. In other words, renewable generators are paid for the power that they deliver to the load center, and thus the MPR should be determined at that point on the grid.

The May 20 ALJ Ruling also asks parties to consider how future MPR calculations should be modified to reflect the CAISO's Market Re-design and Technology Update (MRTU), and when any such modifications should be considered. As a threshold matter, the Commission should make certain that MRTU is functioning properly, before its market data is incorporated into benchmarks such as the MPR.[21] That said, there is no question that the nodal prices produced under MRTU should be used to bring greater locational specificity to MPR prices.

Today, GMMs are used for the locational valuation of line loss impacts on the CAISO transmission grid. GMMs measure the average transmission line losses to deliver power to a virtual load center. The valuation of line losses will change under MRTU. The new locational marginal price (LMP) method will provide a line loss component of the market price at each node on the grid. This market-based line loss component will reflect marginal losses at each node, a significant change from the GMM methodology, which uses losses scaled to system average losses. Under MRTU, the CAISO also will provide aggregated losses across all of the nodes on its system and across each utility's service territory. For example, assume that a new renewable generator's node has an annual average loss component of $1.50 per MWh and the system's annual average loss component is $2.00 per MWh. The MPR applicable to that specific project should be increased by $0.50 per MWh to reflect the ratepayer benefit of the reduced losses associated with that project's favorable location. In this way, an MPR specific to

[21] For example, the Commission recently provided for a six-to-twelve month period to gain experience with MRTU prices before they are used in QF short-term energy pricing. *See* D. 07-09-040, at 67-68.

each project could be determined, in order to reflect accurately a project's site-specific annual losses under MRTU compared to the system average losses.

Today, intra-zonal congestion is not priced in the market or in the MPR. However, under MRTU, the explicit valuation of intra-zonal congestion at each node will be possible, because congestion, like line losses, also will be an explicit component of the LMP price at each node. It will be possible to calculate system average congestion costs and to include them in the statewide MPR. Most important, similar to line losses, the MPR applicable to a specific project could be adjusted to reflect a project's site-specific annual congestion costs under MRTU, compared to the system's annual average congestion costs measured either over the whole CAISO system or over the purchasing utility's service territory.

Finally, MRTU will implement a day-ahead market with visible hourly prices. This data may provide a new and better source of energy-related TOU factors than the opaque and inconsistent approaches that the utilities appear to be using today. MRTU will not, however, implement a capacity market or an all-in market, so MRTU may not provide a final solution to the problem of choosing TOU factors for the RPS program.

MRTU will impact not only the MPR calculation, but other aspects of the RPS program as well, including the least-cost best-fit bid evaluation and possibly the structure of RPS contracts. Once MRTU is functioning well, the Commission should consider, in a coordinated fashion, the multiple impacts of MRTU on the RPS program.

## 3.2. MPR GAS METHODOLOGY AND INPUTS

### 3.2.1. MPR proxy plant assumptions

- Do you agree with the MPR proxy plant operational assumptions set forth in the May 20 ALJ Ruling? If not, discuss which assumptions you disagree with and why.

Yes, CalWEA / CCC / LSA / SA agree that the natural gas portion of the MPR should reflect the costs that a CCGT plant would incur to secure a "long-term fixed-price fuel contract," under either a fixed-forward contract or a rolling forward contract. This is required by P.U. Code Section 399.15(c), which provides that the MPR should reflect "the long-term ownership, operating, and fixed-price fuel costs associated with fixed-price electricity from new generating facilities." In other words, the CCGT has secured a fuel supply that insulates it from future volatility in the natural gas market. Generally, one would expect a buyer to pay a premium over the expected spot price in order to eliminate the risk of future gas price volatility. This is the conclusion of an ongoing study at the Lawrence Berkeley National Lab (LBNL) that has compared gas futures prices to contemporaneous fundamentals-based spot market forecasts.[22] D. 03-06-071, in which the Commission considered an early report from the LBNL researchers, concluded that such a risk price premium should be included in the MPR gas forecast methodology.[23]

- If you agree that the proxy CCGT is able to secure a fixed price fuel contract, is the hedging value of a long-term fixed contract fully reflected in the price?

As stated in the May 20 ALJ Ruling, CalWEA / CCC / LSA / SA do not believe that the current MPR model accurately incorporates the cost premium, above the long-term forecasted market price for natural gas, that a CCGT owner would pay to secure a fixed-price gas supply, thus eliminating the risk of gas price volatility. The problem centers on the use of fundamentals-based forecast of future spot gas prices, for the years after forward gas price data is available from the New York Mercantile Exchange (NYMEX). Two simple changes to the MPR gas price forecast are needed to reflect the full risk price premium in all years of the forecast.

---

[22] *See* M. Bollinger, R. Wiser, and W. Golove, "Accounting for Fuel Price Risk: Using Forward Natural Gas Prices Instead of Gas Price Forecasts to Compare Renewable to Natural Gas–fired Generation" (Lawrence Berkeley National Lab, August 2003). A prior version of this work was M. Bollinger, R. Wiser, and W. Golove, "Quantifying the Value that Wind Power Provides As a Hedge Against Volatile Natural Gas Prices" (LBNL, 2002). The LBNL researchers have updated their analysis annually since 2004. These papers are available at http://eetd.lbl.gov/ea/EMS/reports/53587.pdf or http://eetd.lbl.gov/ea/ems/reports/54751.pdf.

[23] D. 03-06-071, at 22-23 and Finding of Fact 17.

First, NYMEX now reports Henry Hub natural gas forward prices for twelve years forward, through 2020. The MPR gas forecast should use the full set of available NYMEX data. CalWEA / CCC / LSA / SA believe that there is adequate open interest in the last six years of NYMEX contracts for the Commission to have confidence in the price data for these years, particularly given the Commission's practice to sample forward price data over an entire month.

Second, for the remaining years 13 - 30 of the long-term gas forecast, the Commission should add a premium to the fundamentals forecast that reflects any observed premium in the forward market, above the fundamentals forecast, over the last five years for which forward market data is available (i.e. years 8 - 12). The Union of Concerned Scientists (UCS) has proposed a similar method, which uses the escalation in the fundamentals forecast to escalate the last year of available NYMEX data. CalWEA / CCC / LSA / SA prefer their approach, because it does not rely so heavily on the last year of NYMEX data.

The May 20 ALJ Ruling asked parties to comment on a regression method that E3 proposed at the workshop as another means to extend forward gas prices. This method would develop a regression of NYMEX forward prices as a function of both (1) time and (2) the fundamentals forecast. This regression would be used to extend the NYMEX futures prices to years 13 - 30. We have examined the E3 regression proposal using data from both the adopted 2007 MPR model and recent forward price data for the month ending May 12, 2008. Because the fundamentals forecast is expressed only as annual average prices, we have used annual average prices in this analysis. The forward price data for both 2007 and 2008 show significant backwardation in the early years of the future price series – in other words, prices decline significantly in the early years – while there is not a similar trend in the fundamentals forecast. As a result, the difference between futures prices and the fundamentals forecast decreases from year to year over the initial 12 years. Not surprisingly, E3's regression analysis projects a continuation of this trend into years 13 - 30, such that the regression line for forward prices actually drops

below the fundamentals forecast in the later years of the forecast period.[24] In effect, the regression produces a risk premium that decreases the further out into the future one goes. This decrease is an artifact of a regression that uses the initial backwardation of forward prices; we do not believe that it makes sense that the market's perceived risks of volatile spot gas prices should decline over time. Accordingly, we still prefer our proposed method, which calculates a risk premium for years 13 - 30 based on the difference between futures and fundamentals prices in years 8 - 12, after the initial backwardation of forward prices has ended. **Figure 1** compares our recommended approach to the UCS and E3 proposals, using updated NYMEX data.

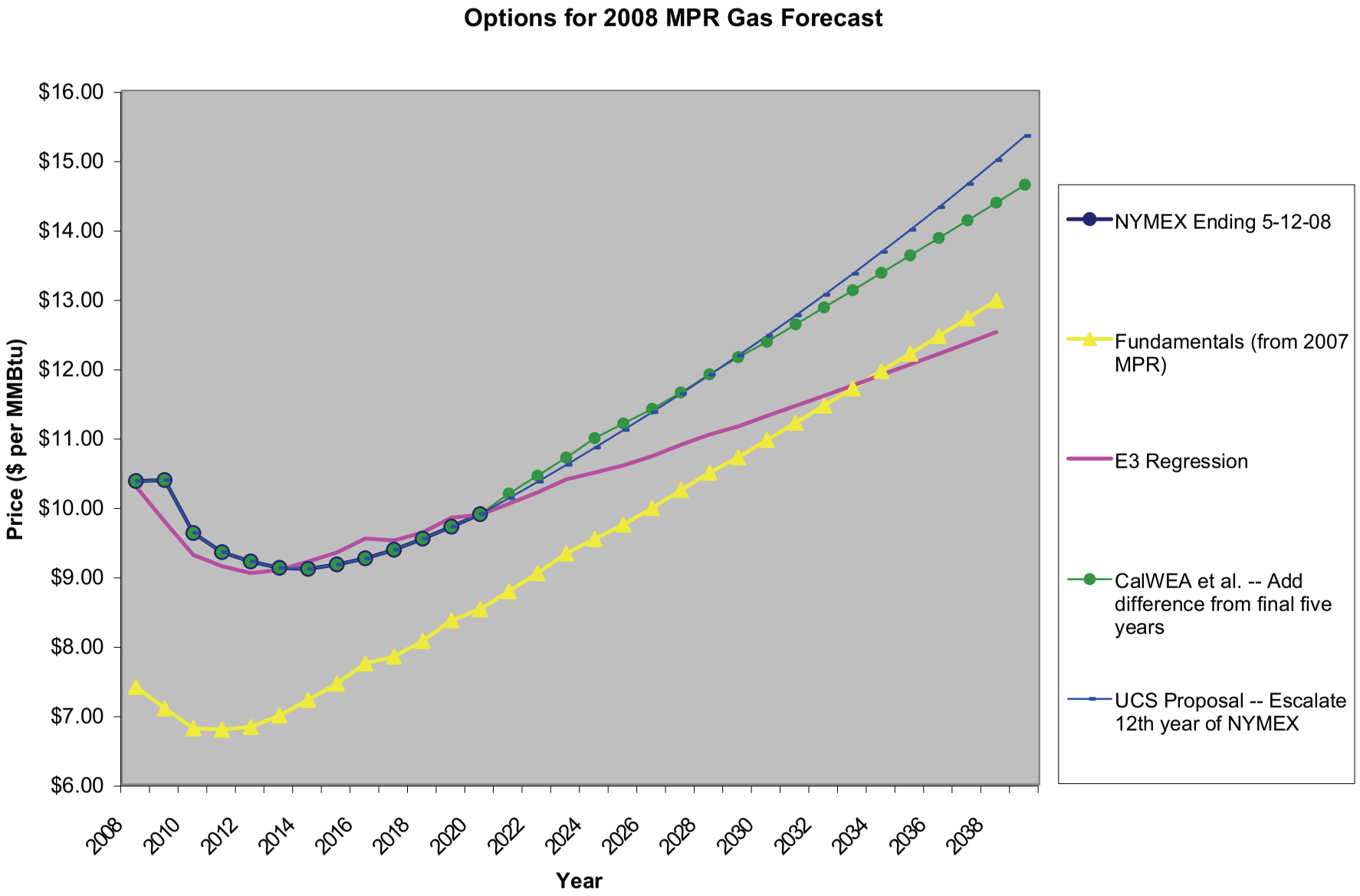
- The CEC's Integrated Energy Policy Report (IEPR) is supported by a long-term natural gas forecast which is researched and calculated by CEC staff with the support of consultants. The CEC's report forecasts natural gas prices over the 2007-2017 period and is considered as a "reference case." Please comment on whether the CEC's long-term gas forecast should be included as an additional public fundamental forecast for the MPR gas methodology.

The difficulty with using the CEC forecast is that it does not extend past the period for which NYMEX forward price data is available. Fundamentals forecasts that do not reflect risk premiums should be not used when forward market data is available that does include such premiums.

Finally, the May 20 ALJ Ruling asks for comments on whether to use the full 72 months of California basis swap data that is now available from NYMEX. CalWEA / CCC / LSA / SA generally support using as much market data as possible, but observe that 72 months of basis swap data is available only for the southern California border market (Topock), but not for the PG&E City-gate market. We suggest using the additional three years of Topock basis data as a guide to extend the PG&E City-gate basis series, as the two markets are closely connected.

[24] If the Commission were to adopt the E3 regression, the Commission should use the higher of the regression forecast or the fundamentals forecast.

**Figure 1**




*Crossborder Energy*

3.3. GHG ADDER

- In view of the GHG policy development and analysis underway in R.06-04-009 to model the cost of compliance with Assembly Bill (AB) 32 (Nunez/Pavley), Stats. 2006, ch. 488, within the electricity sector, should a comprehensive change to the MPR methodology to include a GHG adder be made now for 2008 and beyond? Why or why not? If a permanent change should be made in 2008, how should the GHG adder be developed? Please specifically identify methods, inputs, and models that should be used.

- Should another interim GHG adder be used for the 2008 MPR? If so, should the same methodology that was adopted for the 2007 MPR be used? If a different methodology is recommended, please specify the methods, inputs, and models that should be used. If the same methodology is recommended, please identify any updates to the inputs that should be included.

CalWEA / CCC / LSA / SA continue to support the use of a GHG adder to the MPR, and believe that such an adder should be a permanent feature of the MPR. The Commission has endorsed the concept that the point of regulation for GHG emissions in the electric sector will be the entity that delivers power to the grid, such as the operator of a CCGT. In addition, California's GHG regulation in the electric sector will include a market-based cap-and-trade mechanism.[25] As a result, we fully expect that the long-term market price of electricity after January 1, 2012 will reflect the costs of mitigating GHG emissions, and that a typical CCGT will be exposed to the associated GHG costs on the margin.

Although a GHG adder should be a permanent feature of the MPR methodology, the 2004 GHG mitigation costs used to calculate the 2007 GHG adder are now out-of-date, and should be updated to reflect more recent and realistic data on those costs. Other than this update to GHG costs, no other changes to the 2007 MPR are needed. Realistically, we recognize that California's regulatory program for GHGs is still evolving and that the GHG emission values used in the GHG adder will need further revision in the future, as the AB 32 regulatory program is developed and implemented. Over time, we will gain more information on the costs of GHG mitigation, through both direct regulation and market-based mechanisms. However, there is much

[25] *See* D. 08-03-018, at

more information available today on GHG mitigation costs than was available to E3 in 2004 when they proposed the costs on which the 2007 GHG adder is based. As a result, as discussed below and in our pre-workshop comments, there are credible new sources of data on GHG mitigation costs.

- Identify key criteria the Commission should consider when evaluating parties' proposals for adopting a GHG adder for the MPR methodology.

We recommend that the Commission use the following key criteria as a guide to setting the GHG adder in the 2008 MPR:

  - The GHG adder should reflect up-to-date market data or studies on GHG mitigation costs.
  - Climate change is a worldwide problem that will need to be addressed by many, if not most, of the developed and developing countries of the world. As a result, the Commission should not ignore data on GHG mitigation costs in other regions of the developed world.
  - If the Commission considers data on prices in carbon markets, the Commission should place the most reliance on markets in which participation is mandatory, and should place the most emphasis on prices in the largest and best-developed markets.
  - To the extent that the GHG adder relies on projections of future GHG costs, the Commission should use an average or consensus of multiple relevant studies.

- Comment on CalWEA's proposal to employ a 2008 GHG adder value based on the European Union's carbon market and in future years adopt the Synapse mid-case values as the MPR's GHG adder methodology. Explain why you favor or oppose CalWEA's proposal.

We explain below how the CalWEA / CCC / LSA / SA proposal meets each of the criteria presented above.

**Up-to-date Data.** In 2004, E3 reviewed modeling work on reaching the $CO_2$ emission

targets under the Kyoto Protocol and limited data from the initial efforts in European Union (EU) countries to trade carbon offsets. The E3 Report recommended $8 per ton of $CO_2$ in 2004, escalating at 5% per year, or $9.72 per ton of $CO_2$ in 2008. The Commission adopted these values in D. 04-12-048 and used them in the 2007 MPR. E3 chose these values from the low end of the range of GHG emission costs at that time, and characterized them as "reasonable and conservative, albeit uncertain."[26] Today, much broader, market-based measures of GHG mitigation costs are available, such as the prices in the EU's active carbon allowance market, the world's largest. The EU market includes a forward market for emission allowances, and recent forward prices for 2008 have averaged $29 per short ton.[27] Today's carbon market values are well above E3's 2004 GHG mitigation costs used in the 2007 GHG Adder.

**Look to EU Data for Current GHG Mitigation Costs.** GHG emissions are a planetary problem, and ultimately will have to be addressed on a worldwide basis. As a result, in the interim until California's own GHG regulations are in place and functioning, the state should look to the EU market – the largest, broadest, and most comprehensive carbon allowance market in the world – for data on the current costs of mitigating GHG emissions in the developed world. As noted above, the Commission's current GHG emission costs also were derived from the EU market – in 2004 E3 looked to the prices in the early stages of the EU carbon market in recommending the $8 per ton of $CO_2$ that the Commission subsequently adopted. Accordingly, the Commission should base its GHG adder for 2008 on the market for EU emission offsets in 2008, which are currently trading at $29 per short ton.

---

[26] "Methodology and Forecast of Long-term Avoided Costs for the Evaluation of California Energy Efficiency Programs," prepared by E3 for the CPUC's Energy Division (October 25, 2004); hereafter, the "E3 Report." The E3 Report is available at www.ethree.com/cpuc_avoidedcosts.html. See Section 2.4.4, pages 82-89, of the E3 Report for its discussion of the costs of mitigating GHG emissions. The quote cited is on page 89.

[27] GHG price data for Europe was taken from http://www.europeanclimateexchange.com. Exchange rates are listed at http://www.x-rates.com to convert to U.S. dollars. The $29 per short ton value is an average over the 50 trading days ending February 19, 2008.

As support for the use of current EU GHG values, the Commission also should consider the costs of several of the "early action" measures that the Commission and the California Air Resources Board have approved, as shown in Table 5 of our pre-workshop comments. These early action measures show that California has, in the words of the Commission in adopting the SB 1368 Emission Performance Standard in D. 07-01-039, "raised the bar" in its GHG mitigation actions.[28] These recent Commission actions to "raise the bar" provide ample justification for the Commission, in this proceeding, to increase the outdated 2004 GHG mitigation values used in the 2007 MPR's GHG adder.

**Use the Synapse "Study of Studies."** In addition, there is a rapidly expanding body of modeling studies on the expected long-term costs to meet GHG emission goals. In 2007, Synapse Energy Economics prepared a meta-study of the available models of long-term GHG mitigation costs, including models run by EIA, EPA, MIT, and the Tellus Institute.[29] Synapse used this work to prepare low, medium, and high projections for GHG mitigation costs in 2020 and 2030, as shown in Table 6 of our pre-workshop comments. The principal author of this work, David Schlissel, discussed it at the March 27 workshop.

Following the criteria explained above, CalWEA / CCC / LSA / SA recommend that the GHG mitigation costs in the 2008 GHG adder should use current EU carbon prices of $29 per ton for 2008, then increase over time to Synapse's medium projections for 2020 ($36 per ton) and 2030 ($65 per ton).

---

[28] D. 07-01-039, at 34.

[29] Synapse Energy Economics, "Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning," at 50-55. This study is an attachment to testimony filed before the Florida Public Service Commission in March 2007, and is available at http://www.synapse-energy.com/Downloads/SynapseTestimony.2007-03.Earthjust.FPL-Glades-Coal-Plants-GHG-&-CO2.07-017A.pdf.

3.4 MPR ADMINISTRATION

### 3.4.1 MPR Contract Term Lengths

- Comment on CalWEA's proposal that ED modify the MPR model to accommodate 25 and 30 year RPS contracts. Specifically, identify potential benefits and risks to the RPS program and ratepayers associated with 25 and 30 year fixed price contracts.

The current RPS program requires that the utilities offer RPS contracts with terms of up to 20 years. There is nothing in the RPS rules that prohibits a utility from offering an RPS contract with a longer term, such as 25 or 30 years. Indeed, several projects have obtained 25- or 30-year RPS contracts, which has required the Commission to extend the MPR model to the longer terms. Longer RPS contract terms would help to moderate future RPS bids, as capital-intensive renewable projects could spread their capital costs over more years. The useful life of these generation projects will extend well beyond 20 years, as shown by the many renewable QF projects developed in the 1980s under 30-year contracts that today have operated successfully for 20 - 25 years.

We anticipate that the Commission soon will be asked to require the utilities to offer RPS contracts with terms of 25 or 30 years. To accommodate longer contracts without undue effort, the Energy Division should modify the MPR model so that, if such a change is approved, the 2008 MPR can be calculated for projects with 25- or 30-year contracts.

### 3.4.2 Confidentiality

- Do you agree with PG&E that the MPR has become a price target for renewable developers negotiating contracts with the three large IOUs? If possible, provide supporting documentation.

30

- If so, comment on whether the MPR should be adopted confidentially and the strengths and weaknesses of doing so. How would the Commission update, evaluate and adopt

---

[30] CEC, *2007 IEPR*, at 182-183.

future MPRs if the process were to be made confidential?

- Should the Commission keep confidential whether RPS contracts are above or below the MPR in its resolutions and decisions?

CalWEA / CCC / LSA / SA strongly oppose PG&E's request to make the MPR confidential. To our knowledge, PG&E has offered no evidence that RPS bidders are influenced by the MPR, and has made only the simplistic observation that both the MPR and RPS bids have increased over time. Of course both have increased – the MPR is driven largely by fossil fuel prices and the costs of building power plants, which also are the two major influences on the cost of renewable technologies. The Commission is well aware that high fossil fuel prices and concerns about climate change have caused a strong worldwide demand for renewable generation equipment. The booming economies in China and India have increased the demand for fossil fuel and are a significant factor in higher construction costs. The same factors that are driving CCGT capital costs sharply higher – rapidly escalating costs for construction commodities such as steel, concrete, copper, etc. – also are impacting the capital costs for renewable generation. The Brattle Report, at pages 9-10, discusses how the above factors have caused significant increases in the cost of wind turbines in the U.S. PG&E should do the renewable community the courtesy of separating out from RPS bids the influences of these other factors, before it accuses renewable developers of anti-competitive behavior.

Competition among renewable developers is a cornerstone of the RPS program. If PG&E believes that certain bids have been unduly influenced by the MPR, then PG&E simply can reject those bids, and accept lower bids that have not been so influenced. If PG&E has convincing empirical evidence that this competition is ineffective because many RPS bidders are "chasing the MPR,"[31] and that PG&E is not receiving enough competitive bids to meet its RPS obligations, PG&E should put this evidence before the Commission. Then the Commission can take

[31] Furthermore, PG&E has not described how developers' bids are influenced by the MPR, given that the precise MPR is not calculated until after RPS bids are submitted. There is enough uncertainty in the Energy Division's choice of input assumptions each year, such that it is not easy to project the exact MPR in any year.

appropriate action to re-design the RPS program to use a different approach that does not rely on competitive bids, such as the cost-based feed-in tariffs used widely in Europe.

## CONCLUSION

CalWEA / CCC / LSA / SA respectfully ask the Commission to make the changes to the 2008 MPR that are summarized in Table 1. These modifications are necessary if the MPR is to fulfill the function specified in P.U. Code Section 399.15(c) – to represent "the long-term ownership, operating, and fixed-price fuel costs associated with fixed-price electricity from new generating facilities." Rapidly increasing construction costs and high fossil fuel prices are today's realities. The installed capital costs of a CCGT must reflect the rapid escalation in power plant construction and equipment costs experienced in 2005 - 2007. The determination of the CCGT capacity factor should be simplified to reflect the reality of CCGT operations and economics in the California market. The error in the MPR line loss adjustment should be corrected, to use the weighted average of CAISO GMMs. The GHG adder should become a permanent feature of the MPR, and should be based on the best available information on GHG mitigation costs. This includes current values from the EU carbon market, the world's largest and broadest such market, and from California's own "early action" measures. To forecast GHG emission values over time, the Commission should look to a long-term projection that represents a reasonable middle ground among the growing number of modeling efforts that estimate future GHG mitigation costs. With these changes, the 2008 MPR will fulfill accurately its statutory role of reflecting the full costs of conventional generation in California, including the impacts of increasing construction costs, volatile fossil fuel prices, and the GHG emissions that result from burning natural gas.

Finally, the credibility of the RPS program is important if California is to attract developers willing to invest in bringing the state's abundant renewable resources to market. PG&E's completely unsupported assertion that the MPR causes RPS bidders to submit higher bids should be rejected, and the MPR should remain a transparent benchmark that assures ratepayers that California is receiving a good deal from the RPS program.

CalWEA, CCC, LSA, and SA appreciate the Commission's attention to these comments.

Respectfully submitted,

/ s / R. Thomas Beach

R. Thomas Beach
Patrick G. McGuire
*Crossborder Energy*
2560 Ninth Street, Suite 213A
Berkeley, California 94710
Telephone: 510-549-6922
Facsimile: 510-649-9793
E-mail: tomb@crossborderenergy.com

On Behalf of
**CALIFORNIA WIND ENERGY ASSOCIATION,**
**CALIFORNIA COGENERATION COUNCIL,**
**LARGE-SCALE SOLAR ASSOCIATION, and**
**THE SOLAR ALLIANCE**

June 6, 2008

# Attachment A

PJM Interconnection
Combustion Turbine Cost Estimate

*January 2008*

# 2008 Update of
# Cost of New Entry Combustion Turbine Power Plant
# Revenue Requirements

# For

# PJM Interconnection, LLC.


**Pasteris Energy, Inc.**
**430 Trend Road**
**Yardley, PA 19067**
**Tel. 215-736-817**
**Fax. 215-736-8171**



**January 7, 2008**

# TABLE OF CONTENTS

## TABLE OF CONTENTS (CON'T)

**TABLE OF FIGURES**



**TABLE OF TABLES**



**Addendum No. 1**

## Executive Summary

### Introduction

In August of 2004 PJM retained Pasteris Energy, Inc. ("Pasteris Energy") (formerly Strategic Energy Services, Inc.) to determine the cost of a new entry ("CONE") generation technology and its resulting fixed revenue requirements expressed in $/MW-Year or $/MW-Day as part of the PJM RPM process. The results of that study were issued on August 30, 2005 and were used to determine the upper price boundary of the capacity price demand curve for the four RPM transitional auctions for capacity years 2007-2008, 2008-2009, 2009-2010 and 2010-2010. In accordance with the RPM tariff PJM has updated the CONE revenue requirements for the capacity year 2011-2012. The CONE revenue requirements are based on the total project capital cost and annual fixed operations and maintenance ("O&M") expenses of a combustion turbine ("CT") simple cycle peaker power plant addition within three geographic locations with the PJM region encompassing the following regions. EMAAC comprising the PS, JCP&L, AE, PECO, DPL and RECO zones, SWMAAC comprising the PPL, BGE, PEPCO, MetEd, Penelec, APS, and DQL zones and RTO comprising the AEP, Dominion, Dayton, and ComEd zones. This study has selected sites in New Jersey-EMAAC, Maryland-SWMAAC and Illinois-RTO, respectively. This evaluation only considers capital and fixed O&M costs. Net revenues from the sale of energy and ancillary services are not included in this report and will be determined by PJM.

### Choice of Generation Technology

The August 2005 CONE study evaluated two CT technologies. The General Electric 45 MW LM 6000 aero-derivative CT and the 170 MW GE Frame PG7241 ("Frame 7FA") industrial CT. That study determined that the GE Frame 7FA CT provided the lowest fixed revenue requirements versus the GE LM6000 hence the GE Frame 7FA CT was chosen as the CONE technology for the RPM transitional auctions. For this CONE update the GE Frame 7FA revenue requirements will be updated however the GE LM6000 CT will not be reviewed and updated.

New power generation technology is continually being developed and introduced to the markets by original equipment manufacturers. These new technologies could ultimately replace traditional equipment as the lowest cost source of new generation and have been evaluated as part of the RPM CONE update. Since the 2005 CONE study was completed both GE and Siemens have introduced new CT and/or plant designs which have been evaluated in this study. GE has introduced the LMS-100, a nominal 100 MW high efficiency aero-derivative CT with a heat rate of approximately 9,100 BTU/kWh (HHV). Only one LMS-100 is currently in operation and was installed at the Basin Power Cooperative Groton Station in South Dakota. A second unit is scheduled for commercial operation in June 2008 at the same location.

Also Siemens has recently developed a simplified combined cycle power plant technology known as the FlexPlant10. The FlexPlant10 utilizes the Siemens 5000F 185 MW CT (Formerly the Westinghouse 501F) in a nominal 250 MW combined cycle plant with a net heat rate of approximately 8,000 BTU/kWh (HHV). The single pressure heat recovery steam generator ("HRSG") reduces capital costs over traditional three-pressure reheat combined cycle plants, provides rapid startup and operating flexibility.

**Evaluation Methodology**

Three CT power plant design configurations were initially evaluated in the EMAAC-New Jersey site of PJM. These design configurations include the original CONE, consisting of two GE Frame 7FA units totaling 336 MW, the GE LMS-100 CT consisting of three units totaling 292 MW and a single combined cycle train Siemens FlexPlant10 totaling 250 MW. The CT power plant configuration emerging with the lowest fixed revenue requirements would be further evaluated for the SWMAAC-Maryland site and the RTO-Illinois site.

The Wood Group, a power plant design build firm with CT construction and O&M experience was again contracted by Pasteris Energy to update the plant proper capital cost estimates for the two unit GE Frame 7FA CT and GE LMS-100 aero-derivative CT plants. The Wood Group assembled these estimates based on major equipment quotations, balance of plant material costs and man-hours based on prevailing union labor rates in the designated region. The plant proper estimate is an engineering, procurement and construction ("EPC") turnkey proposal as if contracted to the Wood Group to fully implement the project "turnkey" in current 2008 dollars. The Wood Group operations division also provided assistance in determining plant startup staffing and expenses, capitalized spare parts, O&M staffing, and annual maintenance expenses. Siemens provided comparable plant proper capital costs and annual O&M estimates for the FlexPlant10 plant. Pasteris Energy determined and updated other development expenses such as land, environmental permitting, legal, project management and interest during construction. Pasteris Energy utilized PJM's capital cost database to estimate electric interconnection and system upgrade costs. Pasteris Energy determined the annual property tax payments and plant insurance premiums.

**Proforma Analysis**

A twenty (20) year after tax discounted cash flow ("ATDCF") model was used to determine the levelized revenue requirements for the CONE CT project to cover capital recovery, annual fixed O&M expenses and earn the target after tax return on equity ("ROE") for the investor/owner. The mid-year convention was used to account for revenues and expenses incurred continuously throughout each year in the 20 year project evaluation. This methodology for evaluating power generation investments is the most commonly used by power plant owners and developers. Accordingly, the financial results of this study will be consistent with the financial results obtained by owners and developers when applying the study capital costs, annual O&M expenses and financial criteria. The model only accounted for the capital costs to develop and construct the plant and annual fixed O&M expenses. It includes, fixed capacity revenue, fixed O&M expense, debt service, depreciation, income taxes and after tax cash flow. Variable operating expenses such as fuel and variable operations and maintenance ("VOM") expenses were not included in the financial model. Theses variable expenses are accounted for in the PJM net energy and ancillary services net revenue determination made by PJM.

**Financial Criteria**

Target Return on Equity ("ROE")

A target ROE of 12% was chosen for the proforma evaluation and is based on achieving this ROE in year 20 of the project life. This investment hurdle rate represents a mature and properly functioning capacity market, which provides appropriate and reasonably stable capacity revenues.

Debt to Equity Ratio

A 50% debt to 50% equity ratio was assumed in the proforma model evaluation. This ratio is consistent with the financial structure of a creditworthy integrated electric utility company or independent power company ("IPP"). This would be a reasonable financial structure for the CONE CT plant project.

Debt Term and Interest Rate

Consistent with the financial structure of a creditworthy integrated electric utility company or IPP a long term, 20-year, bond with an interest rate of 7.0 % was used in the proforma model. A mortgage style loan was used which provides for increasing principal payment and decreasing interest payments over the loan term.

Tax Depreciation

The federal tax code allows for CT only power plants to utilize Modified Accelerated Cost Recovery System ("MACRS") over a 15 year tax life for simple cycle plants and 20 year tax life for combined cycle plants on the qualifying portions of the total project cost.

Federal and State Income Taxes

A 35.0% federal income tax rate was used in the proforma model. The state tax rate for New Jersey was 9.0 %, Maryland, 7.0% and Illinois 7.3%.

Escalation

An annual escalation rate of 2.5% was assumed for all fixed O&M expenses over the entire project life.

**CONE Revenue Requirement Results**

The resulting CONE CT capital costs and fixed revenue requirements for the three power plant configurations may be found on Tables 1 and 2 below. The GE Frame 7FA CT plant required significantly lower fixed revenue than that of the GE LMS-100 Aero CT plant and the Siemens FlexPlant10 combined cycle plant. Accordingly, the current 7FA CT plant will be retained by PJM as the CONE CT for all regions of PJM for the 2011-2012 capacity year.

**Table 1**

**ALTERNATIVE CT TECHNOLOGY - CAPITAL COST**

| EMAAC REGION | CAPACITY | CONE 2005 | | CONE 2008 | | |
|---|---|---|---|---|---|---|
| | MW | $000 | $/kW | $000 | $/kW | Increase |
| Current GE Frame 7FA | 336.1 | $156,636 | $466.09 | $206,310 | $613.90 | 1.317 |
| GE LMS-100 | 292.6 | NA | NA | $263,360 | $900.13 | NA |
| Siemens FlexPlant10 | 503.6 | NA | NA | $474,449 | $942.11 | NA |

**Table 2**

**ALTERNATIVE CT TECHNOLOGY - LEVELIZED REVENUE REQUIREMENT RESULTS**

| CONFIGURATION | GE FRAME 7FA | | | | | GE LMS-100 | | SIEMENS FLEXPLANT10 | |
|---|---|---|---|---|---|---|---|---|---|
| EMAAC REGION | CONE 2005 | | CONE 2008 | | | CONE 2008 | | CONE 2008 | |
| | $/MW-Day | $/MW-Year | $/MW-Day | $/MW-Year | Increase | $/MW-Day | $/MW-Year | $/MW-Day | $/MW-Year |
| Capital | $159.77 | $58,316 | $210.39 | $76,794 | 1.317 | $307.93 | $112,393 | $339.57 | $123,944 |
| Fixed O&M | $38.06 | $13,891 | $37.98 | $13,862 | 0.998 | $46.77 | $17,072 | $51.24 | $18,704 |
| Total Fixed | $197.83 | $72,207 | $248.37 | $90,656 | 1.256 | $354.70 | $129,465 | $390.82 | $142,648 |

In Table 2 revenue requirements are presented in $/MW-Year and $/MW-Day and are total levelized. The total levelized value represents constant, non-escalating annual capacity revenues over the 20-year project life beginning in 2008 and having the same NPV as the 20-year revenue requirements escalating at 2.5% starting in 2008.

The results of evaluating the revenue requirements of the Frame 7FA CT plant for the New Jersey, Maryland and Illinois plant sites are found on Table 3. The differences in revenue requirements are primarily a result of construction labor and O&M labor rates, land costs, property taxes and state tax rates. Table 3 also provides the revenue requirements of the previous CONE CT for the transitional auctions and a projection of the revenue requirements for the CONE start of operation on June 1, 2011. Details on the methodology used to update the CONE capital cost and fixed revenue requirement to current 2008 dollars and the projection of these costs to the capacity year 2011-2012 are found in the details of this report.

**Table 3**

**CONE CAPITAL COST AND REVENUE REQUIREMENTS**
**FRAME 7FA PLANT**

| CONE Capital Costs | Previous CONE | | CONE January 1, 2008 | | CONE January 1, 2010 SOC [4] | |
|---|---|---|---|---|---|---|
| Geographic Location Within PJM | $Million | $/kW | $Million | $/kW | $Million | $/kW |
| EMAAC [1] | $156.636 | $466.09 | $206.310 | $613.90 | $244.740 | $728.25 |
| SWMAAC [2] | $158.525 | $471.71 | $202.030 | $601.16 | $239.354 | $712.22 |
| RTO [3] | $159.749 | $475.35 | $203.795 | $606.41 | $241.894 | $719.78 |

| Previous CONE | | | | | | |
|---|---|---|---|---|---|---|
| Geographic Location Within PJM | EMAAC [1] | | SWMAAC [2] | | RTO [3] | |
| Levelized Revenue Requirements | $/MW-Day | $/MW-Year | $/MW-Day | $/MW-Year | $/MW-Day | $/MW-Year |
| Capital | $159.77 | $58,316 | $161.20 | $58,837 | $162.80 | $59,422 |
| Fixed O&M | $38.06 | $13,891 | $41.86 | $15,280 | $39.57 | $14,444 |
| Total | $197.83 | $72,207 | $203.06 | $74,117 | $202.37 | $73,866 |

| CONE January 1, 2008 | | | | | | |
|---|---|---|---|---|---|---|
| Geographic Location Within PJM | EMAAC [1] | | SWMAAC [2] | | RTO [3] | |
| Levelized Revenue Requirements | $/MW-Day | $/MW-Year | $/MW-Day | $/MW-Year | $/MW-Day | $/MW-Year |
| Capital | $210.39 | $76,794 | $205.16 | $74,882 | $207.00 | $75,555 |
| Fixed O&M | $37.98 | $13,862 | $40.62 | $14,825 | $35.98 | $13,134 |
| Total | $248.37 | $90,656 | $245.77 | $89,707 | $242.98 | $88,689 |

| CONE January 1, 2010 SOC with June 1, 2011 COD [5] | | | | | | |
|---|---|---|---|---|---|---|
| Geographic Location Within PJM | EMAAC [1] | | SWMAAC [2] | | RTO [3] | |
| Levelized Revenue Requirements | $/MW-Day | $/MW-Year | $/MW-Day | $/MW-Year | $/MW-Day | $/MW-Year |
| Capital | $249.69 | $91,136 | $243.11 | $88,736 | $245.43 | $89,582 |
| Fixed O&M | $43.20 | $15,768 | $45.69 | $16,678 | $40.21 | $14,678 |
| Total | $292.89 | $106,904 | $288.81 | $105,414 | $285.64 | $104,260 |

| Plant Description | |
|---|---|
| CT Model | GE Frame 7FA |
| Number of CTs | 2 |
| Plant Capacity (MW) | 336.066 |
| Heat Rate (BTU/kWh) (HHV) | 10,826 |
| **Financial Assumptions** | |
| Percent Equity | 50% |
| Percent Debt | 50% |
| Debt Term (Years) | 20 |
| Project Life (Years) | 20 |
| Debt Interest Rate (%) | 7.0% |
| Target Equity IRR (%) | 12.0% |
| General Escalation (%) | 2.5% |
| MARCS Depreciation (Yrs) | 15 |

[1] EMAAC encompasses the PS, JCP&L, AE, PECO, DPL and RECO zones.

[2] SWMAAC encompasses the PPL, BGE, PEPCO MetEd, Penelec, APS and DQL zones.

[3] RTO encompasses the AEP, Dominion, Dayton and ComEd zones.

[4] SOC = Start of Construction

[5] COD = Commercial Operation Date

## 1.0 CONE Plant Design

### 1.1 GE Frame 7FA Plant

Since GE Frame 7FA has been chosen as the CONE only details of that generation technology will be presented in this report. I supplemental expanded report will be issued providing details on the GE LMS-100 and the Siemens FlexPlant10 plants.

Since its introduction to the markets about fifteen years ago the GE Frame 7FA has been a technically and commercially successful combustion turbine in simple and combined cycle operation. The particular model used in this study is the PG7241. Many of these units have been installed in the PJM system in simple and combined cycle configuration. There are greater then thirty GE Frame 7FA units currently installed and operating in the PJM region.

The Frame 7FA CT plant design for this CONE update is the same as the original CONE study which consists of two GE Frame 7FA units. This is consistent with the majority of new CT plants constructed in PJM having two or more GE Frame 7FA units. The primary fuel is natural gas with No. 2 oil as liquid fuel backup. It is assumed that pipeline gas is available at adequate pressure to be utilized by the CT without on site fuel gas compression. The minimum fuel gas pressure requirement of the GE Frame 7FA is 450 PSIG.

The Frame 7FA, when firing natural gas, utilizes dry low NOx ("DLN") combustor technology to reduce NOx emissions to 9.0 PPM at 15% $O_2$. Selective Catalytic Reduction ("SCR") technology has been added to further reduce emissions from the stack to 2.5 PPM at 15% $O_2$. Due to the high exhaust temperatures of the Frame 7FA CT, which are greater than 1,100° F, cooling air is introduced upstream of the SCR to lower and control the exhaust temperatures to an acceptable temperature range of 850° F for the SCR operation. Cooling air fans and associated ductwork are included in the Frame 7FA CT plant scope and capital cost. A hot SCR catalyst design is incorporated. 9.0 PPM emissions from one CT represent approximately 62.0 pounds per hour of NOx. Reducing the NOx level to 2.5 PPM through the SCR reduces the emissions to approximately 17.2 pounds per hour per CT. Assuming two CT units both operating 1,500 hours annually the NOx emissions are 25.8 Tons per year. While firing distillate fuel water injection is used to reduce emissions from the CT to 42 PPM. At this NOx level entering the SCR achieving a stack NOx level of 2.5 PPM would not be expected. Accordingly, the plant may be limited to a specified, not to exceed annual operating hours on oil.

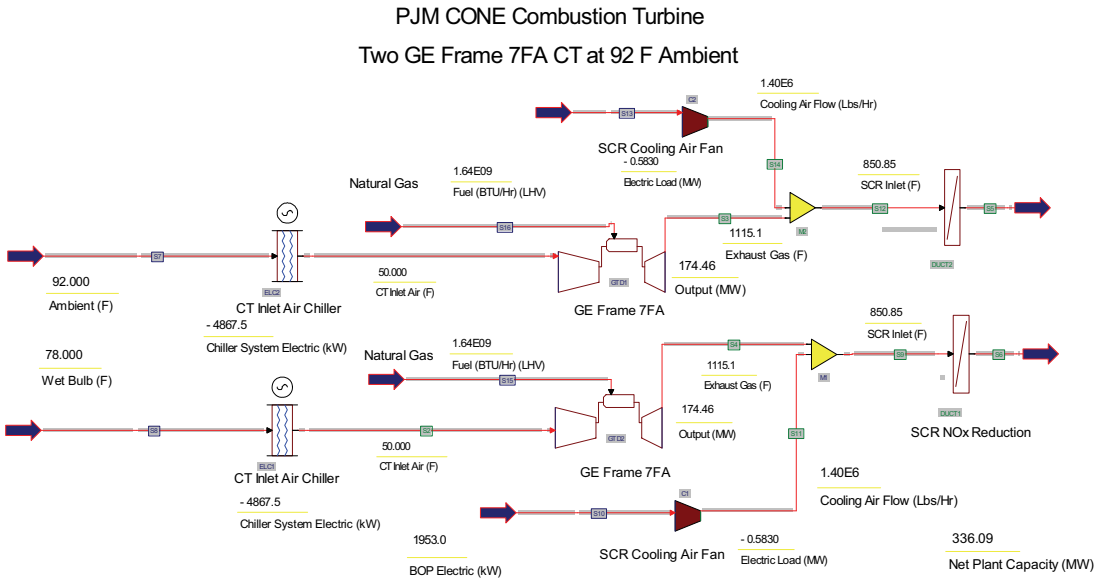
The unit is not designed with black start capability. Because of the large mass of the rotating elements the Frame 7FA windings in the electric generator are used to start the unit. Smaller CT units typically use an external motor driven hydraulic system for startup. Accordingly, it was deemed impractical to consider black start for the Frame 7FA. No black start ancillary service revenues are available from the CONE Frame 7FA CT plant.

Turbine inlet air-cooling to 50° F is included in the Frame 7FA CT plant design. Electric motor driven mechanical chillers will chill water to approximately 40° F. The chilled water is pumped through a heat exchange coil located upstream of the CT compressor inlet and cools the CT compressor inlet air. The CT electric capacity and heat rate are

equal to that of a 50° F ambient day in spite of actual ambient temperatures greater than 50° F.

Figure 1 provides details of the Frame 7FA CT plant under ambient conditions of a 92° F dry bulb temperature and a 78° F wet bulb temperature. The net electric capacity of the Frame 7FA CT plant is 336.1 MW. This capacity is net of the chiller system parasitic load of 9,735 kW. Each CT output is 174.46 MW. Without turbine inlet cooling the net electric capacity is 297.33 MW with each CT output at only 150.21 MW. The net plant capacity increase due to inlet air-cooling is 38.8 MW. Evaporative cooling was evaluated and would yield a net plant capacity of 312.0 MW at the same ambient conditions. Each CT output would be 157.54 MW. Mechanical refrigeration provides a net plant capacity gain of 24.1 MW over evaporative cooling. The incremental capital cost of the mechanical chiller system is approximately $12.0 Million. This investment increases capacity by 38.8 MW making the cost of inlet air cooling only $309.29 per kW. This is well below the plant proper cost of $524.47 per kW without inlet cooling. Accordingly, the inlet air cooling investment lowers the overall plant proper cost to $499.72 per kW.

**Figure 1**




## 2.0 Construction Scope and Capital Cost

### 2.1 Plant Proper Capital Cost

The Wood Group, a power plant design build firm with CT plant design and construction experience, was retained by Pasteris Energy to update the plant proper capital cost estimates for the Frame 7FA CT plant. The Wood Group developed the capital cost for the original CONE CT plant in 2005. The Wood Group assembled capital cost estimates based on equipment quotations, materials, man-hours based on prevailing union labor rates in the designated PJM regions. The plant proper estimate is an engineering, procurement and construction ("EPC") turnkey cost as if contracted to the Wood Group

expressed in instantaneous January 1, 2008 dollars. The Frame 7FA CT plant proper cost for New Jersey plant site was estimated at $167.941 Million, for Maryland plant site at $162.669 and for Illinois plant site at $164.645.

In order to project plant proper capital costs to the start of construction on January 1, 2010 Pasteris Energy presented PJM two year to ten year historical Handy Whitman indices and escalation for the construction costs of combustion turbine based power plants. These historical indices and escalation are presented in the following Table 4. PJM chose the "Last 2 Year" annual escalation rate of 10.0 % which increased plant proper capital cost on January 1, 2008 by a factor of 1.209 for January 1, 2010 at start of construction. Pasteris Energy calculated the projected capital cost accordingly.

**Table 4**
**Handy Whitman Index**
**Total Other Production Plant (CT Based)**

| Mid -Year | Handy Whitman Index | Annual Escalation |
|---|---|---|
| 1997 | 378 | |
| 1998 | 388 | 1.026 |
| 1999 | 404 | 1.041 |
| 2000 | 440 | 1.089 |
| 2001 | 420 | 0.955 |
| 2002 | 437 | 1.040 |
| 2003 | 444 | 1.016 |
| 2004 | 447 | 1.007 |
| 2005 | 450 | 1.007 |
| 2006 | 471 | 1.047 |
| 2007 | 543 | 1.153 |

| Historical Average Escalation | |
|---|---|
| Historical Term | Average Annual Escalation |
| Last 10 Years | 1.038 |
| Last 5 Years | 1.046 |
| Last 4 Years | 1.053 |
| Last 3 Years | 1.069 |
| Last 2 Years | 1.100 |

## 2.2 Construction and Draw Down Schedules

The Wood Group also provided construction and draw down schedules. The construction schedule for the Frame 7FA CT plant is 18 months. The construction and draw down schedule were used by Pasteris Energy to determine interest during construction.

## 2.3 Black Start Capability

Black start capability is not included in the Frame 7FA CT plant as the unit is not started via a separate motor driven hydraulic system but utilizes the generator winding as a motor to start the unit using electric from the system. The required installed oil fired diesel generator capacity exceeds 8.0 MW to start a single Frame 7FA CT and was deemed not cost effective.

## 2.4 Duel Fuel Capability

The Frame 7FA CT plants are capable of natural gas and No. 2 oil operation and the necessary equipment including on site fuel oil storage has been included in the plant proper capital cost.

## 3.0 Other Project Capital Costs

### 3.1 Electric Interconnection

In the normal course of power project development the PJM Transmission Planning Department manages the capital costs for plant direct interconnection to the PJM system as well as the cost of PJM system upgrades. For the CONE CT update evaluation 172 power plant interconnection and system upgrade costs were available in the database for proposed, in construction and recently completed power projects. Project installed capacities ranged from 1 MW to 830 MW. The database was sorted into a 100 MW to 400 MW capacity range that represented the range of the CONE CT projects under evaluation. This capacity range produced 17 projects with an average direct interconnection cost of $12.12 per kW and $6.54 per kW for PJM system upgrades. This produced at total interconnection cost of $18.66 per kW of installed net plant capacity. This value was increased by $2.00 per kW to a value of $20.66 per kW net plant capacity to include power lines from the CONE CT plant to the PJM interconnection point. This cost is down from a total of $22.30 per kW from the original CONE study. These costs were reduced due to the cost sharing of interconnection and system upgrade costs among generation and transmission project owners. Since the PJM records showed capital cost de-escalation for power plant interconnection and system upgrade costs so the same $20.66 per kW capital cost was used for the January 1, 2010 start of construction projection.

### 3.2 Natural Gas Interconnection

PJM does not compile a database of natural gas interconnection costs. The pipeline distance from the plant to the high-pressure gas interconnection point is assumed to be 5 miles or less. The CONE CT evaluation assumes that natural gas is available at a pressure level adequate to be used directly in the CT without on site fuel gas compression. For the Frame 7FA CT plant this pressure is assumed to be 450 PSIG. The Wood Group provided estimates for the natural gas metering station at the plant site. These costs were estimated at $1,000,000 for the Frame 7FA CT plant in 2005. Based on further input from The Wood Group and review of other available information a cost of $20.77 per net kW capacity was utilized in 2005 to represent the total cost of natural gas interconnection that includes the metering stations and a gas pipeline outside the plant proper. To determine the 2008 cost of the natural gas interconnection the Handy-Whitman Index for gas transmission construction from 2005 to 2008 was used. This index yielded a cost increase of 10.5% or $22.95 per net kW. In order to determine the January 1, 2010 start of construction cost projection the average annual escalation from 2005 to 2008 was applied forward to 2010 resulting in an additional increase of 6.4% to $24.41 per kW.

### 3.3 Plant Mobilization and Startup Costs

As a power plant nears construction completion the owner begins to mobilize for the commissioning, testing and startup. These costs are typically capitalized and include hiring, relocation expenses, and labor costs of the O&M staff 5 to 6 month before startup, training, production of O&M manuals, special tools and office equipment and furnishings. Startup consumables were also capitalized which include purchased electricity, fuel, water and chemicals.

The Wood Group operations division provided the mobilizations costs for the Frame 7FA CT plant. The Wood Group operations division provides startup, operations and maintenance services for CT based power plants. The 2008 mobilization cost for the Frame 7FA CT plant was estimated at $1,588,409.

Fuel, water and electric costs were assumed to include 72 hours of CT full load testing and 3,600 hours or 5 months of plant parasitic electric load purchased from the local utility. No credit was taken for electric revenues during plant testing. The consumable expenses for the Frame 7FA CT plant were estimated by Pasteris Energy to be $2,400,895. The total cost is $3,989,304.

In order to determine the January 1, 2010 start of construction cost projection for plant mobilization and start up labor and materials were increased by long term historical annual CPI of 2.5%. Gas and electric prices were not escalated. This resulted in a weighted increase of 2.0 % over the two year period from 2008 to 2010. The total cost is projected to be $4,069,720.

**3.4 Initial Capitalized Spare Parts Inventory**

The Wood Group estimated the spare parts inventory consistent with their estimate for startup and O&M services provided to the CONE CT plants. The capitalized spare parts for the Frame 7FA CT plant were estimated at $2,000,000 in 2005. To determine the 2008 cost of capitalized spare parts the Handy-Whitman Index for gas turbo-generators from 2005 to 2008 was used. This index yielded a cost increase of 29.3% or a capitalized spare parts cost of $2,585,915. In order to determine the January 1, 2010 start of construction cost projection the average annual escalation from 2005 to 2008 was applied forward to 2010 resulting in an additional increase of 15.1% to $2,976,526.

**3.5 Project Development Costs**

Internal and contracted expenses for professional services can be capitalized. These costs include, development, legal, financial and technical professionals during the development, construction and startup of the project. Pasteris Energy, having experience in power project development, estimated these costs. The development costs for the Frame 7FA CT plant was estimated at $2,250,000 in 2005. To determine the 2008 development cost historical 2005 to 2008 CPI escalation was used yielding a 9.06% increase to $2,453,769. In order to determine the January 1, 2010 start of construction cost projection project development costs were increased by long term historical annual CPI of 2.5%. This resulted in a 2010 cost of $2,577,991.

Environmental and regulatory professional services and application fees to obtain air, land use and FERC permits were estimated at $1,500,000 for the Frame 7FA CT plant in 2005. Again to determine the 2008 development cost historical 2005 to 2008 CPI escalation was used yielding a 9.06% increase to $1,635,846. In order to determine the January 1, 2010 start of construction cost projection project environmental services costs were increased by long term historical annual CPI of 2.5%. This resulted in a projected cost of $1,718,661.

**3.6 Land Costs**

The 2005 cost of property for siting the CONE CT plant was obtained by contacting real estate agencies in south New Jersey, Maryland and northern Illinois. The 2005 average cost for the New Jersey plant site property was $20,000 per acre, for the Maryland plant site property, $40,000 per acre and for the Illinois plant site property, $40,000 per acre. For the CONE 2008 update real estate agencies were again contacted and property values have increased reasonably close to that of CPI. Accordingly, CPI escalation was applied yielding for the New Jersey plant site property $21,811 per acre, for the Maryland plant site property, $43,623 per acre and for the Illinois plant site property, $43,623 per acre. In order to determine the January 1, 2010 start of construction cost projection property costs were increased by long term historical annual CPI of 2.5%. This resulted in a projected cost for the New Jersey plant site property of $22,915 per acre, for the Maryland plant site property, $45,831 per acre and the Illinois plant site property, $45,831 per acre.

The Wood Group provided a plot plan for each CONE CT plant. The plant proper foot print for the Frame 7FA CT plant was 6.75 acres. A land buffer area was added surrounding plant proper foot print equal to 8 times the plant proper foot print. The total purchased property for the Frame 7FA CT plant is 60.75 acres.

**3.7 Interest During Construction**

Interest during construction ("IDC") was determined based on the construction costs and monthly draw down schedules provided by The Wood Group. An interest rate of 5.0% was utilized for the calculation of IDC. The 2005 CONE Study used an IDC interest rate of 3.5%. This 5.0% interest rate was again used for the 2010 start of construction cost projections.

**3.8 Owner's Contingency**

In the 2005 CONE an owner's contingency was added to the total project capital cost of 2.5% of the plant proper engineering, procurement and construction cost. This 2.5% contingency was used for the 2008 CONE and the 2010 start of construction cost projection.

**3.9 Emissions Reduction Credits**

Pasteris Energy retained the Air Resources Group, LLC of Albany, New York to assist in determining ERC requirements of the CONE plant.

In New Jersey and Maryland NOx offsets are purchased at 1.3:1 ratio for each ton of NOx emitted by the plant. Thus the expected plant NOx emissions of 25.8 tons per year would require the purchase 33.54 tons of NOx ERCs. In Illinois plant NOx emissions are below the ERCs requirement threshold in all of the counties so ERC purchases are not required. For the ERCs in the more severe areas of New Jersey and Maryland a cost of $10,000 per ton of NOx was assumed. This resulted in an upfront ERC purchase cost of $335,400 for New Jersey and Maryland plant sites. ERC purchased cost for the Illinois plant site is zero.

In all three PJM regions the plant will need NOx budget allowances under the CAIR program. It is assumed that no new source set aside allowances that will be available thus the plant will be required to tap the auction market for its initial year allowances. Thus,

these costs would also be capitalized. Assuming a cost of $1,000 per ton of NOx a cost of $25,800 is also included for all three plant sites for the first year allocation of NOx budget allowances. No escalation or adjustments were made to ERC costs to determine the January 1, 2010 start of construction projection.

Details of the CT plant scope, capital costs, schedule, startup and annual O&M costs, plant performance and plant drawings provided by the Wood Group may be found in the attached Addendum No. 1. The capital cost buildup for the Frame 7FA CT plant may be found on Table 5.

**Table 5**
**PJM CONE CT UPDATE**
**GE FRAME 7FA CONFIGURATION**
**CAPITAL COST DETAIL BY PJM GEOGRAPHIC LOCATION**

| EMAAC [1] | Previous CONE | | CONE January 1, 2008 | | | CONE January 1, 2010 SOC [4] | | |
|---|---|---|---|---|---|---|---|---|
| | $000 | $/kW | $000 | $/kW | Increase | $000 | $/kW | Increase |
| Plant Proper EPC | $124,648 | $370.90 | $167,941 | $499.72 | 1.347 | $203,122 | $604.41 | 1.209 |
| Electric Interconnect | $7,482 | $22.26 | $6,941 | $20.66 | 0.928 | $6,941 | $20.66 | 1.000 |
| Gas Interconnect | $6,978 | $20.76 | $7,714 | $22.95 | 1.105 | $8,204 | $24.41 | 1.064 |
| Equipment Spares | $2,000 | $5.95 | $2,586 | $7.69 | 1.293 | $2,977 | $8.86 | 1.151 |
| Owners Contingency | $3,116 | $9.27 | $4,199 | $12.49 | 1.347 | $5,078 | $15.11 | 1.209 |
| Mobilization and Startup | $3,498 | $10.41 | $3,989 | $11.87 | 1.140 | $4,070 | $12.11 | 1.020 |
| Land Purchase | $1,212 | $3.61 | $1,322 | $3.93 | 1.091 | $1,389 | $4.13 | 1.051 |
| Development Expenses | $1,500 | $4.46 | $1,636 | $4.87 | 1.091 | $1,719 | $5.11 | 1.051 |
| Legal Fees | $750 | $2.23 | $818 | $2.43 | 1.091 | $859 | $2.56 | 1.051 |
| Interest During Construction | $3,825 | $11.38 | $7,167 | $21.33 | 1.874 | $8,519 | $25.35 | 1.189 |
| Air, EIS, Land Use & FERC Permits | $1,500 | $4.46 | $1,636 | $4.87 | 1.091 | $1,719 | $5.11 | 1.051 |
| Emissions Reductions Credits | $125 | $0.37 | $361 | $1.07 | 2.890 | $361 | $1.07 | 1.000 |
| Total Project Cost | $156,636 | $466.09 | $206,310 | $613.90 | 1.317 | $244,958 | $728.90 | 1.187 |

| SWMAAC [2] | Previous CONE | | CONE January 1, 2008 | | | CONE January 1, 2010 SOC [4] | | |
|---|---|---|---|---|---|---|---|---|
| | $000 | $/kW | $000 | $/kW | Increase | $000 | $/kW | Increase |
| Plant Proper EPC | $125,293 | $372.82 | $162,669 | $484.04 | 1.298 | $196,746 | $585.44 | 1.209 |
| Electric Interconnect | $7,482 | $22.26 | $6,941 | $20.66 | 0.928 | $6,941 | $20.66 | 1.000 |
| Gas Interconnect | $6,978 | $20.76 | $7,714 | $22.95 | 1.105 | $8,204 | $24.41 | 1.064 |
| Equipment Spares | $2,000 | $5.95 | $2,586 | $7.69 | 1.293 | $2,977 | $8.86 | 1.151 |
| Owners Contingency | $3,132 | $9.32 | $4,067 | $12.10 | 1.298 | $4,919 | $14.64 | 1.209 |
| Mobilization and Startup | $3,498 | $10.41 | $3,989 | $11.87 | 1.140 | $4,070 | $12.11 | 1.020 |
| Land Purchase | $2,424 | $7.21 | $2,644 | $7.87 | 1.091 | $2,777 | $8.26 | 1.051 |
| Development Expenses | $1,500 | $4.46 | $1,636 | $4.87 | 1.091 | $1,719 | $5.11 | 1.051 |
| Legal Fees | $750 | $2.23 | $818 | $2.43 | 1.091 | $859 | $2.56 | 1.051 |
| Interest During Construction | $3,842 | $11.43 | $6,970 | $20.74 | 1.814 | $8,280 | $24.64 | 1.188 |
| Air, EIS, Land Use & FERC Permits | $1,500 | $4.46 | $1,636 | $4.87 | 1.091 | $1,719 | $5.11 | 1.051 |
| Emissions Reductions Credits | $125 | $0.37 | $361 | $1.07 | 2.890 | $361 | $1.07 | 1.000 |
| Total Project Cost | $158,525 | $471.71 | $202,030 | $601.16 | 1.274 | $239,571 | $712.87 | 1.186 |

| RTO [3] | Previous CONE | | CONE January 1, 2008 | | | CONE January 1, 2010 SOC [4] | | |
|---|---|---|---|---|---|---|---|---|
| | $000 | $/kW | $000 | $/kW | Increase | $000 | $/kW | Increase |
| Plant Proper EPC | $126,528 | $376.50 | $164,645 | $489.92 | 1.301 | $199,136 | $592.55 | 1.209 |
| Electric Interconnect | $7,482 | $22.26 | $6,941 | $20.66 | 0.928 | $6,941 | $20.66 | 1.000 |
| Gas Interconnect | $6,978 | $20.76 | $7,714 | $22.95 | 0.000 | $8,204 | $24.41 | 1.064 |
| Equipment Spares | $2,000 | $5.95 | $2,586 | $7.69 | 1.293 | $2,977 | $8.86 | 1.151 |
| Owners Contingency | $3,163 | $9.41 | $4,116 | $12.25 | 1.301 | $4,978 | $14.81 | 1.209 |
| Mobilization and Startup | $3,498 | $10.41 | $3,989 | $11.87 | 1.140 | $4,070 | $12.11 | 1.020 |
| Land Purchase | $2,424 | $7.21 | $2,644 | $7.87 | 1.091 | $2,777 | $8.26 | 1.051 |
| Development Expenses | $1,500 | $4.46 | $1,636 | $4.87 | 1.091 | $1,719 | $5.11 | 1.051 |
| Legal Fees | $750 | $2.23 | $818 | $2.43 | 1.091 | $859 | $2.56 | 1.051 |
| Interest During Construction | $3,874 | $11.53 | $7,044 | $20.96 | 1.818 | $8,370 | $24.90 | 1.188 |
| Air, EIS, Land Use & FERC Permits | $1,500 | $4.46 | $1,636 | $4.87 | 1.091 | $1,719 | $5.11 | 1.051 |
| Emissions Reductions Credits | $50 | $0.15 | $26 | $0.08 | 0.516 | $26 | $0.08 | 1.000 |
| Total Project Cost | $159,748 | $475.35 | $203,795 | $606.41 | 1.276 | $241,776 | $719.43 | 1.186 |

[1] **EMAAC encompasses the PS, JCP&L, AE, PECO, DPL and RECO zones.**

[2] **SWMAAC encompasses the PPL, BGE, PEPCO MetEd, Penelec, APS and DQL zones.**

[3] **RTO encompasses the AEP, Dominion, Dayton and ComEd zones.**

[4] **SOC = Start of Construction**

## 4.0 Plant Performance

### 4.1 Plant Net Capacity and Heat Rate

Pasteris Energy utilized GE Energy Services GateCycle power plant performance software to determine the performance of the CONE CT plant at ambient temperatures from 20 F to 100 F. The performance evaluation also included detailed determinations of

the plant parasitic loads for CT inlet air cooling, SCR cooling air and the balance of plant. Table 6 below summarizes the plant performance for the Frame 7FA CT plant.

**Table 6**
**PJM CONE CT PLANT PERFORMANCE**
**TWO GE FRAME 7FA CT UNITS WITH CT INLET AIR CHILLING TO 50 F**

| AMBIENT AND OTHER OPERATING CONDITIONS | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Ambient Temperature (F) | 20.0 | 30.0 | 40.0 | 50.0 | 60.0 | 70.0 | 80.0 | 90.0 | 100.0 |
| Relative Humidity (%) | 60.0% | 60.0% | 60.0% | 60.0% | 60.0% | 60.0% | 60.0% | 60.0% | 60.0% |
| Electric Chiller Status | Off | Off | Off | Off | On | On | On | On | On |
| CT Inlet Air Temperature (F) | 20.0 | 30.0 | 40.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 |
| Chiller System Efficiency (kW/Ton) | NA | NA | NA | NA | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| SCR Cooling Air Flow (Lbs/Hr) | 1,400,000 | 1,400,000 | 1,400,000 | 1,400,000 | 1,400,000 | 1,400,000 | 1,400,000 | 1,400,000 | 1,400,000 |
| SCR Inlet Temperature (F) | 822.6 | 828.7 | 835.3 | 841.9 | 844.4 | 846.7 | 848.5 | 850.2 | 851.6 |
| **PLANT GROSS CAPACITY** | | | | | | | | | |
| CT 1 Gross Capacity (MW) | 183.320 | 180.934 | 177.697 | 174.460 | 174.460 | 174.460 | 174.460 | 174.460 | 174.460 |
| CT 2 Gross Capacity (MW) | 183.320 | 180.934 | 177.697 | 174.460 | 174.460 | 174.460 | 174.460 | 174.460 | 174.460 |
| Plant Gross Capacity (MW) | 366.639 | 361.869 | 355.395 | 348.920 | 348.920 | 348.920 | 348.920 | 348.920 | 348.920 |
| **PLANT PARASITIC LOADS** | | | | | | | | | |
| CT 1 Chiller System Load (kW) | 0 | 0 | 0 | 0 | -567 | -1,569 | -3,091 | -4,954 | -7,264 |
| CT 2 Chiller System Load (kW) | 0 | 0 | 0 | 0 | -567 | -1,569 | -3,091 | -4,954 | -7,264 |
| CT 1 SCR Cooling Air Fan Load (MW) | -0.502 | -0.512 | -0.523 | -0.534 | -0.546 | -0.557 | -0.569 | -0.581 | -0.594 |
| CT 2 SCR Cooling Air Fan Load (MW) | -0.502 | -0.512 | -0.523 | -0.534 | -0.546 | -0.557 | -0.569 | -0.581 | -0.594 |
| BOP Parasitic Load (kW) | 1,953 | 1,953 | 1,953 | 1,953 | 1,953 | 1,953 | 1,953 | 1,953 | 1,953 |
| **PLANT NET CAPACITY** | | | | | | | | | |
| Net Capacity (MW) | **363.683** | **358.891** | **352.395** | **345.898** | **344.742** | **342.716** | **339.648** | **335.898** | **331.251** |
| **PLANT FUEL CONSUMPTION AND HEAT RATE** | | | | | | | | | |
| CT 1 Fuel (MMBTU/Hr) (LHV) | 1,720.9 | 1,697.7 | 1,670.7 | 1,643.5 | 1,643.5 | 1,643.5 | 1,643.5 | 1,643.5 | 1,643.5 |
| CT 2 Fuel (MMBTU/Hr) (LHV) | 1,720.9 | 1,697.7 | 1,670.7 | 1,643.5 | 1,643.5 | 1,643.5 | 1,643.5 | 1,643.5 | 1,643.5 |
| Total Plant Fuel (MMBTU/Hr) (LHV) | 3,441.8 | 3,395.3 | 3,341.3 | 3,287.0 | 3,287.0 | 3,287.0 | 3,287.0 | 3,287.0 | 3,287.0 |
| Total Plant Fuel (MMBTU/Hr) (HHV) | 3,810.1 | 3,758.7 | 3,698.8 | 3,638.7 | 3,638.7 | 3,638.7 | 3,638.7 | 3,638.7 | 3,638.7 |
| Net Plant Heat Rate (BTU/kWh) (HHV) | **10,476** | **10,473** | **10,496** | **10,520** | **10,555** | **10,617** | **10,713** | **10,833** | **10,985** |
| CT Only Gross Heat Rate (BTU/kWh) (LHV) | 9,388 | 9,383 | 9,402 | 9,421 | 9,421 | 9,421 | 9,421 | 9,421 | 9,421 |

## 4.2 NOx Emissions Controls

The Frame 7FA CT plant utilized dry low NOx ("DLN") combustor technology to control NOx at 9 PPM exiting the CT while firing natural gas. While firing No. 2 oil water injection is used to control the NOx level at 42 PPM. Selective Catalytic Reduction ("SCR") technology was employed to further reduce NOx to 2.5 PPM exiting the stack.

## 4.3 Ancillary Services

The Frame 7FA CT plant configuration is capable of supplying reactive power as an ancillary service. No additional capital cost is included for this service as leading power factor capability is standard design for the electric generators. Black start capability is not included in the Frame 7FA CT plant as the unit is not started via a separate motor driven hydraulic system but utilizes the generator winding as a motor to start the unit using electric from the system. The required installed oil fired diesel generator capacity exceeds 8.0 MW to start a single Frame 7FA CT and was deemed not cost effective.

# 5.0 Annual Fixed Operating Expenses

## 5.1 Operations and Maintenance Staffing

The Wood Group operations division provided the O&M staffing and expense for the Frame 7FA CT plant. The staffing complement for the Frame 7FA CT plant is nine (9) on-site personnel.

A 52.5% benefits and G&A burden was added to the base hourly rate as well as 25% overtime hours above the base 2,080 hours at a time and one half hourly rates. This

results in a 2008 fully loaded annual labor expense of $1,325,343 or $147,261 per person per year for the Frame 7FA CT plant. In order to determine the June 1, 2011 start of operation cost projection O&M staffing and expenses were increased by long term historical annual CPI of 2.5%. This resulted in a projected cost of $1,427,249. These costs are for the New Jersey plant site. Costs for the Maryland and Illinois plant sites are slightly different due to adjustments in regional labor rates.

### 5.2 Contract Parts and Labor

The Wood Group operations division provided the annual contract parts and labor expenses for both the Frame 7FA CT plant which were $389,663. In order to determine the June 1, 2011 start of operation cost projection contract parts and labor expenses were increased by long term historical annual CPI of 2.5%. This resulted in a projected cost of $419,624.

### 5.3 Insurance Expenses

Overall power plant annual insurance premiums were estimated to be 0.5% of the insured asset value. In the CONE CT study insurance was extended to the plant proper, the electric interconnection, the gas interconnection and capitalized spare parts. Coverage included general liability, property, boiler and machinery and business interruption. This amounts to approximately $926,000 annual premium for the Frame 7FA CT plant at the New Jersey site. Insurance premiums varied slightly for the Maryland and Illinois sites based on asset value. Guidelines for the determination of insurance premiums were provided by Moore-McNeil LLC Insurance Consulting. The same annual insurance premium factor of 0.5% of the insured asset value was used for the June 1, 2011 start of operation.

### 5.4 Property Tax

In the original 2005 CONE study property taxes were determined for plant site location in New Jersey, Maryland and Illinois by obtaining public information on actual taxes paid by recently constructed power plant. This information was obtained from FERC filings or directly from the township or county tax assessors. These rates for power plants were compared with statutory tax rates in the counties and townships where the plants were constructed as well as surrounding counties and townships. In all cases the power plant tax rates were lower then the statutory rates indicating that development/enterprise zone tax relief was made available or payments in lieu of taxes ("PILOT") were negotiated. The average of the actual tax rates incurred by the power plants surveyed in each region was used in this study. For New Jersey the tax rate was $2.53 per $1,000 of assessed value, for Maryland the tax rate was $4.50 per $1,000 of assessed value and for Illinois the tax rate was $2.09 per $1,000 of assessed value. The assessed value was determined to be all fixed assets based on the plant proper construction capital cost and all interconnection costs plus net current assets which would include capitalized spare parts.

For the 2008 CONE update the same methodology was used as in 2005. The survey of current tax rates determined that property tax rates increased only in New Jersey by 11.02%. Property tax rates in Maryland and Illinois remained unchanged. In order to determine the June 1, 2011 start of operation cost projection property taxes were increased in New Jersey again by 11.02% while Maryland and Illinois are assumed to again remain unchanged.

## 5.5 General and Administrative Expenses

General and administrative expense cover any technical, legal, accounting and permitting fees incurred on an annual basis. Annual G&A expenses were estimated by the Wood Group at $211,532. In order to determine the June 1, 2011 start of operation cost projection G&A expenses were increased by long term historical annual CPI of 2.5%. This resulted in a projected cost of $227,797.

The detailed annual fixed O&M expenses for the first year of operation for the Frame 7FA CT plant are summarized on the following Table 7.

**Table 7**
**PJM CONE CT UPDATE**
**GE FRAME 7FA CONFIGURATION**
**FIRST YEAR ANNUAL FIXED O&M EXPENSES BY PJM GEOGRAPHIC LOCATION**

| EMAAC [1] | Previous CONE | | | CONE January 1, 2008 | | | | CONE June 1, 2011 COD [4] | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | $000 | $/MW-Day | $/MW-Year | $000 | $/MW-Day | $/MW-Year | Increase | $000 | $/MW-Day | $/MW-Year | Increase |
| Site O &M Labor | $1,268 | $10.33 | $3,772 | $1,325 | $10.80 | $3,944 | 1.046 | $1,427 | $11.64 | $4,247 | 1.077 |
| O&M Contract Parts & Labor | $232 | $1.89 | $689 | $390 | $3.18 | $1,159 | 1.682 | $420 | $3.42 | $1,249 | 1.077 |
| Electric Purchases | $200 | $1.63 | $595 | $218 | $1.78 | $649 | 1.091 | $235 | $1.91 | $699 | 1.077 |
| Training-Employee Expenses | $74 | $0.60 | $220 | $89 | $0.73 | $265 | 1.203 | $96 | $0.78 | $285 | 1.077 |
| O & M Management Fee | $250 | $2.04 | $744 | $245 | $2.00 | $729 | 0.980 | $264 | $2.15 | $785 | 1.077 |
| Property, Machinery, B I Insurance | $1,411 | $11.50 | $4,199 | $926 | $7.55 | $2,755 | 0.656 | $1,106 | $9.02 | $3,292 | 1.195 |
| G&A | $161 | $1.31 | $478 | $212 | $1.72 | $629 | 1.317 | $228 | $1.86 | $678 | 1.077 |
| Property Taxes | $395 | $3.22 | $1,177 | $578 | $4.71 | $1,719 | 1.461 | $754 | $6.15 | $2,244 | 1.306 |
| Total | $3,991 | $32.53 | $11,874 | $3,982 | $32.47 | $11,850 | 0.998 | $4,530 | $36.93 | $13,479 | 1.137 |

| SWMAAC [2] | Previous CONE | | | CONE January 1, 2008 | | | | CONE June 1, 2011 COD [4] | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | $000 | $/MW-Day | $/MW-Year | $000 | $/MW-Day | $/MW-Year | Increase | $000 | $/MW-Day | $/MW-Year | Increase |
| Site O &M Labor | $1,344 | $10.96 | $3,999 | $1,299 | $10.59 | $3,865 | 0.966 | $1,399 | $11.40 | $4,162 | 1.077 |
| O&M Contract Parts & Labor | $232 | $1.89 | $689 | $390 | $3.18 | $1,159 | 1.682 | $420 | $3.42 | $1,249 | 1.077 |
| Electric Purchases | $200 | $1.63 | $595 | $218 | $1.78 | $649 | 1.091 | $235 | $1.91 | $699 | 1.077 |
| Training-Employee Expenses | $74 | $0.60 | $220 | $89 | $0.73 | $265 | 1.203 | $96 | $0.78 | $285 | 1.077 |
| O & M Management Fee | $250 | $2.04 | $744 | $245 | $2.00 | $729 | 0.980 | $264 | $2.15 | $785 | 1.077 |
| Property, Machinery, B I Insurance | $1,418 | $11.56 | $4,219 | $900 | $7.33 | $2,677 | 0.634 | $1,074 | $8.76 | $3,197 | 1.194 |
| G&A | $161 | $1.31 | $478 | $212 | $1.72 | $629 | 1.317 | $228 | $1.86 | $678 | 1.077 |
| Property Taxes | $713 | $5.81 | $2,122 | $907 | $7.40 | $2,700 | 1.273 | $1,076 | $8.77 | $3,203 | 1.186 |
| Total | $4,391 | $35.80 | $13,067 | $4,259 | $34.72 | $12,673 | 0.970 | $4,791 | $39.06 | $14,257 | 1.125 |

| RTO [3] | Previous CONE | | | CONE January 1, 2008 | | | | CONE June 1, 2011 COD [4] | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | $000 | $/MW-Day | $/MW-Year | $000 | $/MW-Day | $/MW-Year | Increase | $000 | $/MW-Day | $/MW-Year | Increase |
| Site O &M Labor | $1,470 | $11.98 | $4,374 | $1,286 | $10.48 | $3,825 | 0.875 | $1,384 | $11.29 | $4,120 | 1.077 |
| O&M Contract Parts & Labor | $232 | $1.89 | $689 | $390 | $3.18 | $1,159 | 1.682 | $420 | $3.42 | $1,249 | 1.077 |
| Electric Purchases | $200 | $1.63 | $595 | $218 | $1.78 | $649 | 1.091 | $235 | $1.91 | $699 | 1.077 |
| Training-Employee Expenses | $74 | $0.60 | $220 | $89 | $0.73 | $265 | 1.203 | $96 | $0.78 | $285 | 1.077 |
| O & M Management Fee | $250 | $2.04 | $744 | $245 | $2.00 | $729 | 0.980 | $264 | $2.15 | $785 | 1.077 |
| Property, Machinery, B I Insurance | $1,430 | $11.66 | $4,255 | $909 | $7.41 | $2,706 | 0.636 | $1,086 | $8.86 | $3,232 | 1.194 |
| G&A | $161 | $1.31 | $478 | $212 | $1.72 | $629 | 1.317 | $228 | $1.86 | $678 | 1.077 |
| Property Taxes | $333 | $2.71 | $991 | $425 | $3.46 | $1,264 | 1.276 | $504 | $4.11 | $1,500 | 1.186 |
| Total | $4,149 | $33.83 | $12,347 | $3,773 | $30.76 | $11,228 | 0.909 | $4,217 | $34.38 | $12,548 | 1.118 |

[1] EMAAC encompasses the PS, JCP&L, AE, PECO, DPL and RECO zones.
[2] SWMAAC encompasses the PPL, BGE, PEPCO MetEd, Penelec, APS and DQL zones.
[3] RTO encompasses the AEP, Dominion, Dayton and ComEd zones.
[4] COD = Commercial Operation Date

## 6.0 Financial Criteria

## 6.1 Proforma Analysis

A twenty (20) year after tax discounted cash flow ("ATDCF") model was used to determine the real levelized and levelized revenue requirements for the CONE CT project. Revenues determined covered capital recovery, annual fixed O&M expenses and earned the target return on equity for the investor/owner. The mid-year convention was used to account for revenues and expenses incurred continuously throughout each year in the 20 year project evaluation. This methodology for evaluating power generation investments is the most commonly used by owners and developers. Accordingly, the

financial results of this study will be consistent with the financial results obtained by developers when applying the CONE CT study capital costs, annual O&M expenses and financial criteria. The model only accounted for the capital costs to construct the plant and annual fixed operation and maintenance expenses of the project 20-year life. It includes, fixed revenue, annual fixed O&M expense, debt service, depreciation, income taxes and after tax cash flow. Variable operating expenses such as fuel and variable operations and maintenance expenses ("VOM") where not included in the model.

**6.2 Financial Criteria**

Target Return on Equity

A target internal rate of return on equity ("ROE") of 12% was chosen for the proforma evaluation and is based on achieving that IRR in year 20 of the project life. This investment hurdle rate represents a mature and properly functioning capacity market, which provides appropriate and reasonably stable capacity revenues.

Debt to Equity Ratio

A 50/50 debt to equity ratio was assumed in the proforma model evaluation. This ratio is consistent with the financial structure of a creditworthy integrated electric utility company or independent power company ("IPP"). This would be a reasonable financial structure for a CONE CT project.

Debt Term and Interest Rate

Consistent with the financial structure of a creditworthy integrated electric utility company a long term, 20-year, bond with an interest rate of 7.0 % was used in the proforma model. A mortgage style loan was used which provides for increasing principal payment and decreasing interest payments over the loan term.

Tax Depreciation

The federal tax code allows for CT only power plant to utilize Modified Accelerated Cost Recovery System ("MACRS") over a 15 year tax life and 20 year tax life for combined cycle plants on the qualifying portions of the total project cost.

Federal and State Income Taxes

A 35.0% federal income tax rate was used in the proforma model. The state tax rate for New Jersey was 9.0 %, Maryland, 7.0% and Illinois 7.3%.

Escalation

An annual escalation rate of 2.5% was assumed for all fixed expenses over the entire project life.

Reporting of Revenue Requirements

Revenue requirements are presented in $/MW-Year and $/MW-Day and are total levelized. The total levelized value represents constant, non-escalating annual capacity revenues over the 20-year project life beginning in 2008 and having the same NPV as the 20-year revenue requirements escalating at 2.5% starting in 2008.

### 6.3 Proforma Evaluation Methodology

Initially an estimated real levelized annual revenue requirement was input into the proforma model. Next the capital cost and 2008 estimates of fixed O&M expenses were input into the proforma model and allowed to escalate at 2.5% annually to 2011, the first year of operation and for the 20-year project life. Added to these expenses were MACRS tax depreciation and debt interest payments. The difference between revenues and expenses provided the annual taxable income to which the federal income tax and appropriate state taxes were applied. This yielded after tax income. To the after tax income line the loan principal payments were subtracted and depreciation was added back to determine after tax cash flow. The equity placement of 50% of the total project cost was added as a negative cash flow on January 1, 2011 of the first operating year while annual cash flow was assigned a mid-year convention of July 1 for each year in the project life. This 20-year cash flow stream was used to calculate ROE via the MS Excel function XIIR. The levelized annual revenue requirement input was adjusted until the target 12.0% ROE was achieved.

Please be advised that the capital cost and annual fixed O&M values are slightly different from those posted previously on the PJM website prior and for the December 13, 2007 MRC meeting. Changes to Emissions Reduction Credits cost assumptions affected CONE capital costs and property tax escalation assumption affected fixed O&M expenses. Please use the results of this report for your evaluation and analysis of CONE.

## CERTIFICATE OF SERVICE

I hereby certify that I have this day caused to be served a copy of the foregoing document, **Post-Workshop Opening Comments of the California Wind Energy Association, the California Cogeneration Council, the Large-scale Solar Association, and the Solar Alliance**, by Electronic Mail where possible and First-Class Mail where not, on all known parties to R. 06-02-012, named on the service list attached to the original certificate of this document pursuant to the Commission's Rules of Practice and Procedure.

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

Executed at Berkeley, California, Friday, June 6, 2008.

/s/ Christa Goldblatt

Christa Goldblatt

PHILIPPE AUCLAIR
11 RUSSELL COURT
WALNUT CREEK, CA 94598
philha@astound.net

CLARE BREIDENICH
224 1/2 24TH AVE. EAST
SEATTLE, WA 98112
cbreidenich@yahoo.com

GRAIG COOPER
55 2ND STREET, SUITE 525
SAN FRANCISCO, CA 94105
gcooper@cpv.com

PAUL D. HUNT
4929 WEBSTER STREET
OAKLAND, CA 94609-2116
pdh9@columbia.edu

TODD JAFFE
3420 KEYSER ROAD
BALTIMORE, MD 21208
tjaffe@energybusinessconsultants.com

LIZBETH MCDANNEL
2244 WALNUT GROVE AVE., QUAD 4D
ROSEMEAD, CA 91770
lizbeth.mcdannel@sce.com

DAVID MORSE
1411 W, COVELL BLVD., SUITE 106-292
DAVIS, CA 95616-5934
demorse@omsoft.com

DAVID TOWNLEY
18 BASSWOOD AVENUE
OAK PARK, CA 91377
David.Townley@townleytech.com

ROBIN J. WALTHER
1380 OAK CREEK DRIVE, NO. 316
PALO ALTO, CA 94304-2016
rwalther@pacbell.net

KEITH WHITE
312 KELLER ST
PETALUMA, CA 94952
keithwhite@earthlink.net

3 PHASES ENERGY SERVICES
2100 SEPULVEDA BLVD., SUITE 37
MANHATTAN BEACH, CA 90266

MICHAEL MAZUR
3 PHASES RENEWABLES, LLC
2100 SEPULVEDA BLVD. STE 37
MANHATTAN BEACH, CA 90266
mmazur@3phasesRenewables.com

GABE PETLIN
3DEGREES
6 FUNSTON AVENUE
SAN FRANCISCO, CA 94129
gpetlin@3degreesinc.com

DENNIS W. DE CUIR
A LAW CORPORATION
2999 DOUGLAS BLVD., SUITE 325
ROSEVILLE, CA 95661
dennis@ddecuir.com

MARC D. JOSEPH
ADAMS, BROADWELL, JOSEPH & CARDOZO
601 GATEWAY BLVD., STE. 1000
SOUTH SAN FRANCISCO, CA 94080
mdjoseph@adamsbroadwell.com

JAMES WEIL
AGLET CONSUMER ALLIANCE
PO BOX 37
COOL, CA 95614
jweil@aglet.org

GARY COLLORD
AIR RESOURCES BOARD
1001 I STREET, PO BOX 2815
SACRAMENTO, CA 95812
gcollord@arb.ca.gov

KAREN TERRANOVA
ALCANTAR & KAHL, LLP
120 MONTGOMERY STREET, STE 2200
SAN FRANCISCO, CA 94104
filings@a-klaw.com

MICHAEL ALCANTAR
ALCANTAR & KAHL, LLP
120 MONTGOMERY STREET, SUITE 2200
SAN FRANCISCO, CA 94104
mpa@a-klaw.com

DONALD BROOKHYSER
ALCANTAR & KAHL
1300 SW FIFTH AVE., SUITE 1750
PORTLAND, OR 97210
deb@a-klaw.com

ROD AOKI
ALCANTAR & KAHL, LLP
120 MONTGOMERY STREET, SUITE 2200
SAN FRANCISCO, CA 94104
rsa@a-klaw.com

EVELYN KAHL
ALCANTAR & KAHL, LLP
120 MONTGOMERY STREET, SUITE 2200
SAN FRANCISCO, CA 94104
ek@a-klaw.com

NORA SHERIFF
ALCANTAR & KAHL, LLP
120 MONTGOMERY STREET, SUITE 2200
SAN FRANCISCO, CA 94104
nes@a-klaw.com

SEEMA SRINIVASAN
ALCANTAR & KAHL, LLP
120 MONTGOMERY STREET, SUITE 2200
SAN FRANCISCO, CA 94104
sls@a-klaw.com

TODD J. MARTIN
ALTERNITY WIND POWER, LLC
ONE CRAGWOOD ROAD
SOUTH PLAINFIELD, NJ 07080
tmartin@alternitywindpower.com

AMERICAN UTILITY NETWORK
10705 DEER CANYON DRIVE
ALTA LOMA, CA 91737
pssed@adelphia.net

PAUL DELANEY
AMERICAN UTILITY NETWORK (A.U.N.)
10705 DEER CANYON DRIVE
ALTA LOMA, CA 91737
pssed@adelphia.net

GLORIA BRITTON
ANZA ELECTRIC COOPERATIVE, INC.
PO BOX 391909
ANZA, CA 92539
GloriaB@anzaelectric.org

AOL UTILITY CORP.
12752 BARRETT LANE
SANTA ANA, CA 92705

STACY AGUAYO
APS ENERGY SERVICES
400 E. VAN BUREN STREET, SUITE 750
PHOENIX, AZ 85004
stacy.aguayo@apses.com

JENINE SCHENK
APS ENERGY SERVICES
400 E. VAN BUREN STREET, SUITE 750
PHOENIX, AZ 85004
jenine.schenk@apses.com

APS ENERGY SERVICES COMPANY, INC.
400 E. VAN BUREN STREET, SUITE 750
PHOENIX, AZ 85004
stacy.aguayo@apses.com

JOHN R. REDDING
ARCTURUS ENERGY CONSULTING
44810 ROSEWOOD TERRACE
MENDOCINO, CA 95460
johnrredding@earthlink.net

ROGER LEE
BAKER & HOSTETLER LLP
600 ANTON BLVD., SUITE 900
COSTA MESA, CA 92626
rblee@bakerlaw.com

CARL STEEN
BAKER & HOSTETLER LLP
600 ANTON BLVD., SUITE 900
COSTA MESA, CA 92626
csteen@bakerlaw.com

STEVEN S. SCHLEIMER
BARCLAYS BANK, PLC
200 PARK AVENUE, FIFTH FLOOR
NEW YORK, NY 10166
steven.schleimer@barclayscapital.com

BARBARA R. BARKOVICH
BARKOVICH & YAP, INC.
44810 ROSEWOOD TERRACE
MENDOCINO, CA 95460
brbarkovich@earthlink.net

REED V. SCHMIDT
BARTLE WELLS ASSOCIATES
1889 ALCATRAZ AVENUE
BERKELEY, CA 94703-2714
rschmidt@bartlewells.com

RYAN WISER
BERKELEY LAB
1 CYCLOTRON ROAD, MS-90-4000
BERKELEY, CA 94720
rhwiser@lbl.gov

RYAN PLETKA
BLACK & VEATCH
2999 OAK ROAD, SUITE 490
WALNUT CREEK, CA 94597
pletkarj@bv.com

RYAN BERNARDO
BRAUN BLAISING MCLAUGHLIN, P.C.
915 L STREET, SUITE 1270
SACRAMENTO, CA 95814
bernardo@braunlegal.com

SCOTT BLAISING
BRAUN & BLAISING, P.C.
915 L STREET, SUITE 1420
SACRAMENTO, CA 95814
blaising@braunlegal.com

BRUCE MCLAUGHLIN
BRAUN & BLAISING, P.C.
915 L STREET SUITE 1420
SACRAMENTO, CA 95814
mclaughlin@braunlegal.com

BRIAN C. FRECKMANN
C/O FOUNDATION PARTNERS
100 DRAKES LANDING ROAD NO. 125
GREENBRAE, CA 94904
brian@banyansec.com

JAN MCFARLAND
CAEATFA
915 CAPITOL MALL, RM. 457
SACRAMENTO, CA 95814
jmcfarland@treasurer.ca.gov

Amanda C. Baker
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
ab1@cpuc.ca.gov

Paul Douglas
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
psd@cpuc.ca.gov

Dorothy Duda
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
dot@cpuc.ca.gov

Gretchen T. Dumas
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
gtd@cpuc.ca.gov

Julie A. Fitch
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
jf2@cpuc.ca.gov

Anne Gillette
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
aeg@cpuc.ca.gov

Louis M. Irwin
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
lmi@cpuc.ca.gov

Sara M. Kamins
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
smk@cpuc.ca.gov

Cheryl Lee
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
cnl@cpuc.ca.gov

Mark R. Loy
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
mrl@cpuc.ca.gov

Jaclyn Marks
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
jm3@cpuc.ca.gov

Burton Mattson
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
bwm@cpuc.ca.gov

Beth Moore
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
blm@cpuc.ca.gov

Noel Obiora
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
nao@cpuc.ca.gov

David Peck
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
dbp@cpuc.ca.gov

Brian D. Schumacher
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
bds@cpuc.ca.gov

Andrew Schwartz
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
as2@cpuc.ca.gov

Anne E. Simon
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
aes@cpuc.ca.gov

Sean A. Simon
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
svn@cpuc.ca.gov

Donald R. Smith
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
dsh@cpuc.ca.gov

Elizabeth Stoltzfus
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
eks@cpuc.ca.gov

DAN ADLER
CALIFORNIA CLEAN ENERGY FUND
5 THIRD STREET, SUITE 1125
SAN FRANCISCO, CA 94103
Dan.adler@calcef.org

BETH VAUGHAN
CALIFORNIA COGENERATION
COUNCIL
4391 N. MARSH ELDER COURT
CONCORD, CA 94521
beth@beth411.com

HOLLY B. CRONIN
CALIFORNIA DEPARTMENT OF
WATER RESOURCES
3310 EL CAMINO AVE., LL-90
SACRAMENTO, CA 95821
hcronin@water.ca.gov

MOHAN NIROULA
CALIFORNIA DEPARTMENT OF
WATER RESOURCES
3310 EL CAMINO AVENUE, STE 256
SACRAMENTO, CA 95821
mniroula@water.ca.gov

JOSEPH FLESHMAN
CALIFORNIA ENERGY COMISSION
1516 9TH STREET, MS-45
SACRAMENTO, CA 95814
jfleshma@energy.state.ca.us

LORRAINE GONZALES
CALIFORNIA ENERGY COMMISSION
1516 9TH STREET MS-45
SACRAMENTO, CA 95814
lgonzale@energy.state.ca.us

BILL KNOX
CALIFORNIA ENERGY COMMISSION
1516 NINTH STREET, MS 28
SACRAMENTO, CA 95814-5504
bknox@energy.state.ca.us

CLARE LAUFENBERG
CALIFORNIA ENERGY COMMISSION
1516 NINTH STREET, MS 46
SACRAMENTO, CA 95814
claufenb@energy.state.ca.us

HEATHER LOUIE
CALIFORNIA ENERGY COMMISSION
1516 9TH STREET, MS-45
SACRAMENTO, CA 95818
hlouie@energy.state.ca.us

MANPREET MATTU
CALIFORNIA ENERGY COMMISSION
1516 9TH STREET, MS-45
SACRAMENTO, CA 95814
Mmattu@energy.state.ca.us

ROSS MILLER
CALIFORNIA ENERGY COMMISSION
1516 9TH STREET
SACRAMENTO, CA 95814
rmiller@energy.state.ca.us

HEATHER RAITT
CALIFORNIA ENERGY COMMISSION
1516 9TH STREET, MS 45
SACRAMENTO, CA 95814
hraitt@energy.state.ca.us

KATE ZOCCHETTI
CALIFORNIA ENERGY COMMISSION
1516 9TH STREET, MS-45
SACRAMENTO, CA 95814
kzocchet@energy.state.ca.us

CALIFORNIA ENERGY MARKETS
425 DIVISADERO ST.
SAN FRANCISCO, CA 94117
cem@newsdata.com

CALIFORNIA ENERGY MARKETS
425 DIVISADERO ST. SUITE 303
SAN FRANCISCO, CA 94117
cem@newsdata.com

KAREN MILLS
CALIFORNIA FARM BUREAU
FEDERATION
2300 RIVER PLAZA DRIVE
SACRAMENTO, CA 95833
kmills@cfbf.com

CALIFORNIA ISO
151 BLUE RAVINE ROAD
FOLSOM, CA 95630
e-recipient@caiso.com

BALDASSARO DICAPO
CALIFORNIA ISO
151 BLUE RAVINE ROAD
FOLSOM, CA 95630
bdicapo@caiso.com

GRANT A. ROSENBLUM
CALIFORNIA ISO
151 BLUE RAVINE ROAD
FOLSOM, CA 95630
grosenblum@caiso.com

JUDITH SANDERS
CALIFORNIA ISO
151 BLUE RAVINE ROAD
FOLSOM, CA 95630
jsanders@caiso.com

KAREN LINDH
CALIFORNIA ONSITE GENERATION
7909 WALERGA ROAD, NO. 112, PMB
119
ANTELOPE, CA 95843
karen@klindh.com

SARAH BESERRA
CALIFORNIA REPORTS.COM
39 CASTLE HILL COURT
VALLEJO, CA 94591
sbeserra@sbcglobal.net

NANCY RADER
CALIFORNIA WIND ENERGY
ASSOCIATION
2560 NINTH STREET, SUITE 213A
BERKELEY, CA 94710
nrader@calwea.org

KEVIN DUGGAN
CALPINE COPRORATION
3875 HOPYARD ROAD, SUITE 345
PLEASANTON, CA 94588
duggank@calpine.com

AVIS KOWALEWSKI
CALPINE CORPORATION
3875 HOPYARD ROAD, SUITE 345
PLEASANTON, CA 94588
kowalewskia@calpine.com

DANIELLE MATTHEWS SEPERAS
CALPINE CORPORATION
1127 11TH STREET, SUITE 242
SACRAMENTO, CA 95814
dseperas@calpine.com

LINDA Y. SHERIF
CALPINE CORPORATION
3875 HOPYARD ROAD, SUITE 345
PLEASANTON, CA 94588
linda.sherif@calpine.com

VENKAT SURAVARAPU
CAMBRIDGE ENERGY RESEARCH ASSOCIATES
1150 CONNECTICUT AVENUE NW, STE. 201
WASHINGTON, DC 20036

STEVEN SIEGEL
CENTER FOR BIOLOGICAL DIVERSITY
3421 PARK PLACE
EVANSTON, IL 60201
ssiegel@biologicaldiversity.org

JANICE G. HAMRIN
CENTER FOR RESOURCE SOLUTIONS
PO BOX 29512
SAN FRANCISCO, CA 94129
jhamrin@resource-solutions.org

JOSEPH LANGENBERG
CENTRAL CALIFORNIA POWER
949 EAST ANNADALE AVE., A210
FRESNO, CA 93706
Joe.Langenberg@gmail.com

CLAIRE E. TORCHIA
CHADBOURNE & PARKE LLP
350 SOUTH GRAND AVE., STE 3300
LOS ANGELES, CA 90071
ctorchia@chadbourne.com

BILL GOLOVE
CHEVRON ENERGY SOLUTIONS
345 CALIFORNIA STREET, 18TH FLOOR
SAN FRANCISCO, CA 94104
whgolove@chevron.com

STEPHEN A. S. MORRISON
CITY & COUNTY OF SAN FRANCISCO
1 DR CARLTON B. GOODLET PLACE
SAN FRANCISCO, CA 94102-4682
stephen.morrison@sfgov.org

SANDRA ROVETTI
CITY AND COUNTY OF SAN FRANCISCO
1155 MARKET STREET, 4TH FLOOR
SAN FRANCISCO, CA 94103
srovetti@sfwater.org

NEAL DE SNOO
CITY OF BERKELEY
2180 MILVIA AVENUE
BERKELEY, CA 94704
ndesnoo@ci.berkeley.ca.us

KERRY EDEN
CITY OF CORONA DEPT. OF WATER & POWER
730 CORPORATION YARD WAY
CORONA, CA 92880
kerry.eden@ci.corona.ca.us

FREDERICK M. ORTLIEB
CITY OF SAN DIEGO
1200 THIRD AVENUE, SUITE 1200
SAN DIEGO, CA 92101
fortlieb@sandiego.gov

SUSAN MUNVES
CITY OF SANTA MONICA
1212 5TH STREET, FIRST FLOOR
SANTA MONICA, CA 90401
susan.munves@smgov.net

JANIS C. PEPPER
CLEAN POWER MARKETS, INC.
PO BOX 3206
LOS ALTOS, CA 94024
pepper@cleanpowermarkets.com

BILL BARNES
CLEANTECH AMERICA, INC.
50 CALIFORNIA STREET, SUITE 1500
SAN FRANCISCO, CA 94111
b.barnes@cleantechamerica.com

L. JAN REID
COAST ECONOMIC CONSULTING
3185 GROSS ROAD
SANTA CRUZ, CA 95062
janreid@coastecon.com

COURTNEY WEDDINGTON
COMMERCE ENERGY INC
222 W. LAS COLINAS BLVD., STE. 950-E
IRVING, TX 75039
cweddington@commerceenergy.com

ANN HENDRICKSON
COMMERCE ENERGY, INC.
222 WEST LAS COLINAS BLVD., SUITE 950E
IRVING, TX 75039
ahendrickson@commerceenergy.com

TAMLYN M. HUNT
COMMUNITY ENVIRONMENTAL COUNCIL
26 W. ANAPAMU ST., 2ND FLOOR
SANTA BARBARA, CA 93101
thunt@cecmail.org

MELANIE FALLS
COMPETITIVE POWER VENTURES, INC.
55 SECOND STREET, SUITE 525
SAN FRANCISCO, CA 94105

SEAN J. FINNERTY
COMPETITIVE POWER VENTURES, INC.
35 BRAINTREE HILL OFFICE PARK, SUITE 400
BRAINTREE, MA 02184

CYNTHIA A. FONNER
CONSTELLATION ENERGY GROUP INC
500 WEST WASHINGTON ST, STE 300
CHICAGO, IL 60661
Cynthia.A.Fonner@constellation.com

CONSTELLATION NEW ENERGY, INC.
350 SOUTH GRAND AVENUE, SUITE 3800
LOS ANGELES, CA 90071
bill.chen@constellation.com

SARA O'NEILL
CONSTELLATION NEWENERGY, INC.
ONE MARKET STREET, SPEAR TOWER, 36TH FR.
SAN FRANCISCO, CA 94105
sara.oneill@constellation.com

CLYDE MURLEY
CONSULTANT TO NRDC
1031 ORDWAY STREET
ALBANY, CA 94706
clyde.murley@comcast.net

TONY CHEN
COOL EARTH
7665 HAWTHORNE AVE
LIVERMORE, CA 94550
tchen@coolearthsolar.com

MARCIE MILNER
CORAL ENERGY RESOURCES, L P
4445 EASTGATE MALL, SUITE 100
SAN DIEGO, CA 92121
marcie.milner@shell.com

JAMES MCMAHON
CRA INTERNATIONAL
50 CHURCH ST.
CAMBRIDGE, MA 02138
jmcmahon@crai.com

R. THOMAS BEACH
CROSSBORDER ENERGY
2560 NINTH STREET, SUITE 213A
BERKELEY, CA 94710-2557
tomb@crossborderenergy.com

DOUG DAVIE
DAVIE CONSULTING, LLC
3390 BEATTY DRIVE
EL DORADO HILLS, CA 95762
dougdpucmail@yahoo.com

ROBERT B. GEX
DAVIS WRIGHT TREMAINE LLP
505 MONTGOMERY STREET, SUITE 800
SAN FRANCISCO, CA 94111-6533
bobgex@dwt.com

JUDY PAU
DAVIS WRIGHT TREMAINE LLP
505 MONTGOMERY STREET, SUITE 800
SAN FRANCISCO, CA 94111-6533
judypau@dwt.com

JEFFREY P. GRAY
DAVIS WRIGHT TREMAINE, LLP
505 MONTGOMERY STREET, SUITE 800
SAN FRANCISCO, CA 94111-6533
jeffgray@dwt.com

BALWANT S. PUREWAL
DEPARTMENT OF WATER RESOURCES
3310 EL CAMINO AVE., LL-90
SACRAMENTO, CA 95821
bpurewal@water.ca.gov

LARRY F. EISENSTAT
DICKSTEIN SHAPIRO LLP
1825 EYE STREET, NW
WASHINGTON, DC 20006

RICHARD LEHFELDT
DICKSTEIN SHAPIRO LLP
1825 EYE STREET, NW
WASHINGTON, DC 20006

MARK L. PERLIS
DICKSTEIN SHAPIRO LLP
1825 EYE STREET, NW
WASHINGTON, DC 20006
perlism@dicksteinshapiro.com

WILLIAM F. DIETRICH
DIETRICH CONSULTING
2977 YGNACIO VALLEY ROAD, NO. 613
WALNUT CREEK, CA 94598-3535
dietrichlaw2@earthlink.net

RONALD M. CERNIGLIA
DIRECT ENERGY SERVICES, LLC
40 COLUMBINE DRIVE
GLENMONT, NY 12077-2966
ron.cerniglia@directenergy.com

DANIEL W. DOUGLASS
DOUGLASS & LIDDELL
21700 OXNARD STREET, SUITE 1030
WOODLAND HILLS, CA 91367
douglass@energyattorney.com

GREGORY S. G. KLATT
DOUGLASS & LIDDELL
21700 OXNARD STREET, SUITE 1030
WOODLAND HILLS, CA 91367-8102
klatt@energyattorney.com

DONALD C. LIDDELL
DOUGLASS & LIDDELL
2928 2ND AVENUE
SAN DIEGO, CA 92103
liddell@energyattorney.com

DAN L. CARROLL
DOWNEY BRAND LLP
555 CAPITOL MALL, 10TH FLOOR
SACRAMENTO, CA 95814
dcarroll@downeybrand.com

AUDRA HARTMANN
DYNEGY INC.
980 NINTH STREET, SUITE 2130
SACRAMENTO, CA 95814
Audra.Hartmann@Dynegy.com

JOSEPH PAUL
DYNEGY, INC.
4140 DUBLIN BLVD., STE. 100
DUBLIN, CA 94568
joe.paul@dynegy.com

RAMONA GONZALEZ
EAST BAY MUNICIPAL UTILITY DISTRICT
375 ELEVENTH STREET, M/S NO. 205
OAKLAND, CA 94607
ramonag@ebmud.com

AIMEE BARNES
ECOSECURITIES
206 W. BONITA AVENUE
CLAREMONT, CA 91711
aimee.barnes@ecosecurities.com

MARK E. IRWIN
EDISON MISSION ENERGY
18101 VON KARMAN AVE. STE 1700
IRVINE, CA 92612
mirwin@edisonmission.com

ROY D. MCCOY
ELECTRIC RELIABILITY COUNCIL OF TEXAS
2705 W. LAKE DRIVE
TAYLOR, TX 76574
rmccoy@ercot.com

ANDREW B. BROWN
ELLISON SCHNEIDER & HARRIS, LLP
2015 H STREET
SACRAMENTO, CA 95811
abb@eslawfirm.com

JEFFREY HARRIS
ELLISON & SCHNEIDER
2015 H STREET
SACRAMENTO, CA 95811
jdh@eslawfirm.com

GREGGORY L. WHEATLAND
ELLISON SCHNEIDER & HARRIS L.L.P.
2015 H STREET
SACRAMENTO, CA 95811-3109
glw@eslawfirm.com

JEDEDIAH J. GIBSON
ELLISON SCHNEIDER & HARRIS LLP
2015 H STREET
SACRAMENTO, CA 95811
jjg@eslawfirm.com

LYNN M. HAUG
ELLISON, SCHNEIDER & HARRIS, LLP
2015 H STREET
SACRAMENTO, CA 95814-3109
lmh@eslawfirm.com

DOUGLAS K. KERNER
ELLISON, SCHNEIDER & HARRIS, LLP
2015 H STREET
SACRAMENTO, CA 95814
dkk@eslawfirm.com

SNULLER PRICE
ENERGY AND ENVIRONMENTAL ECONOMICS
101 MONTGOMERY, SUITE 1600
SAN FRANCISCO, CA 94104
snuller@ethree.com

STEVE CHADIMA
ENERGY INNOVATIONS, INC.
130 WEST UNION STREET
PASADENA, CA 91103
steve@energyinnovations.com

CAROLYN KEHREIN
ENERGY MANAGEMENT SERVICES
2602 CELEBRATION WAY
WOODLAND, CA 95776
cmkehrein@ems-ca.com

KEVIN J. SIMONSEN
ENERGY MANAGEMENT SERVICES
646 EAST THIRD AVENUE
DURANGO, CO 81301
kjsimonsen@ems-ca.com

DOUGLAS E. COVER
ENVIRONMENTAL SCIENCE ASSOCIATES
225 BUSH STREET, SUITE 1700
SAN FRANCISCO, CA 94104
dcover@esassoc.com

BILL MASON
ENXCO, INC.
PO BOX 581043
N. PALM SPRINGS, CA 92258
billm@enxco.com

KEVIN PORTER
EXETER ASSOCIATES, INC.
5565 STERRETT PLACE
COLUMBIA, MD 21044
porter@exeterassociates.com

SAEED FARROKHPAY
FEDERAL ENERGY REGULATORY COMMISSION
110 BLUE RAVINE RD., SUITE 107
FOLSOM, CA 95630
saeed.farrokhpay@ferc.gov

SAMARA MINDEL
FELLON-MCCORD & ASSOCIATES
9960 CORPORATE CAMPUS DRIVE, SUITE 2000
LOUISVILLE, KY 40223
smindel@knowledgeinenergy.com

BARRY H. EPSTEIN
FITZGERALD,ABBOTT & BEARDSLEY, LLP
1221 BROADWAY, 21ST FLOOR
OAKLAND, CA 94612
bepstein@fablaw.com

JANINE L. SCANCARELLI
FOLGER, LEVIN & KAHN, LLP
275 BATTERY STREET, 23RD FLOOR
SAN FRANCISCO, CA 94111
jscancarelli@flk.com

DIANE I. FELLMAN
FPL ENERGY, LLC
234 VAN NESS AVENUE
SAN FRANCISCO, CA 94102
diane_fellman@fpl.com

GARSON KNAPP
FPL ENERGY, LLC
770 UNIVERSE BLVD.
JUNO BEACH, FL 33408
garson_knapp@fpl.com

STANDISH O'GRADY
FRIENDS OF KIRKWOOD ASSOCIATION
31 PARKER AVENUE
SAN FRANCISCO, CA 94118
sho@ogrady.us

RICH LAUCKHART
GLOBAL ENERGY
2379 GATEWAY OAKS DR.
SACRAMENTO, CA 95833
rlauckhart@globalenergy.com

KEITH SWITZER
GOLDEN STATE WATER COMPANY
630 EAST FOOTHILL BLVD.
SAN DIMAS, CA 91773-9016
kswitzer@gswater.com

RONALD MOORE
GOLDEN STATE WATER/BEAR VALLEY ELECTRIC
630 EAST FOOTHILL BOULEVARD
SAN DIMAS, CA 91773
rkmoore@gswater.com

MICHAEL B. DAY
GOODIN MACBRIDE SQUERI DAY & LAMPREY LLP
505 SANSOME STREET, SUITE 900
SAN FRANCISCO, CA 94111
mday@goodinmacbride.com

JOSEPH F. WIEDMAN
GOODIN MACBRIDE SQUERI DAY & LAMPREY LLP
505 SANSOME STREET, SUITE 900
SAN FRANCISCO, CA 94111
jwiedman@goodinmacbride.com

BRIAN CRAGG
GOODIN, MAC BRIDE, SQUERI, DAY & LAMPREY
505 SANSOME STREET, SUITE 900
SAN FRANCISCO, CA 94111
bcragg@goodinmacbride.com

JAMES D. SQUERI
GOODIN, MACBRIDE, SQUERI, DAY & LAMPREY
505 SANSOME STREET, SUITE 900
SAN FRANCISCO, CA 94111
jsqueri@goodinmacbride.com

GREGORY MORRIS
GREEN POWER INSTITUTE
2039 SHATTUCK AVE., SUITE 402
BERKELEY, CA 94704
gmorris@emf.net

CRAIG LEWIS
GREENVOLTS
50 FIRST STREET, SUITE 507
SAN FRANCISCO, CA 94105
craig.lewis@greenvolts.com

DIARMUID MCGARRY
GREENWOOD ENVIRONMENTAL
330 TOWNSEND ST. SUITE 118
SAN FRANCISCO, CA 94107
diarmuid@greenwoodenv.com

MARY ANNE SULLIVAN
HAGAN & HARTSON, LLP
555 THIRTEENTH STREET, NW
WASHINGTON, DC 20006
MASullivan@hhlaw.com

WILL PLAXICO
HELIOS ENERGY, LLC
31897 DEL OBISPO ST. SUITE 220
SAN JUAN CAPISTRANO, CA 92675
wplaxico@heliosenergy.us

AMY C. ROMA
HOGAN & HARTSON, LLP
555 THIRTEENTH STREET, N.W.
WASHINGTON, DC 20004
ACRoma@hhlaw.com

BRENDA LEMAY
HORIZON WIND ENERGY
1600 SHATTUCK, SUITE 222
BERKELEY, CA 94709
brenda.lemay@horizonwind.com

DONALD N. FURMAN
IBERDROLA RENEWABLES INC
1125 NW COUCH STREET, SUITE 700
PORTLAND, OR 97209

STEVEN KELLY
INDEPENDENT ENERGY PRODUCERS
1215 K STREET, SUITE 900
SACRAMENTO, CA 95814
steven@iepa.com

PETER BREHM
INFINIA CORPORATION
6811 OKANOGAN PLACE
KENNEWICK, WA 99336
pbrehm@infiniacorp.com

MICHAEL J. GILMORE
INLAND ENERGY
3501 JAMBOREE RD
NEWPORT BEACH, CA 92660
michaelgilmore@inlandenergy.com

ALEX KANG
ITRON, INC.
1111 BROADWAY, STE. 1800
OAKLAND, CA 94607
alex.kang@itron.com

JODY S. LONDON
JODY LONDON CONSULTING
PO BOX 3629
OAKLAND, CA 94609
jody_london_consulting@earthlink.net

NELLIE TONG
KEMA, INC.
492 NINTH STREET, SUITE 220
OAKLAND, CA 94607
nellie.tong@us.kema.com

TIMOTHY CASTILLE
LANDS ENERGY CONSULTING, INC.
18109 SE 42ND STREET
VANCOUVER, WA 98683
castille@landsenergy.com

WILLIAM H. BOOTH
LAW OFFICE OF WILLIAM H. BOOTH
67 CARR DRIVE
MORAGA, CA 94596
wbooth@booth-law.com

JEREMY D. WEINSTEIN
LAW OFFICES OF JEREMY D. WEINSTEIN
1512 BONANZA STREET
WALNUT CREEK, CA 94596
jeremy.weinstein@pacificorp.com

SARA STECK MYERS
LAW OFFICES OF SARA STECK MYERS
122 28TH AVE.
SAN FRANCISCO, CA 94121
ssmyers@att.net

JANE H. TURNBULL
LEAGUE OF WOMEN VOTERS OF CALIFORNIA
64 LOS ALTOS SQUARE
LOS ALTOS, CA 94022
jaturnbu@ix.netcom.com

LYNN M. ALEXANDER
LMA CONSULTING
129 REDWOOD AVENUE
CORTE MADERA, CA 94925
lynn@lmaconsulting.com

PATRICK STONER
LOCAL GOVERNMENT COMMISSION
1303 J STREET, SUITE 250
SACRAMENTO, CA 95814
pstoner@lgc.org

PAUL FENN
LOCAL POWER
4281 PIEDMONT AVE.
OAKLAND, CA 94611
paulfenn@local.org

ELIZABETH DOUGLASS
LOS ANGELES TIMES
202 WEST FIRST STREET
LOS ANGELES, CA 90012
elizabeth.douglass@latimes.com

JOHN W. LESLIE
LUCE, FORWARD, HAMILTON & SCRIPPS, LLP
11988 EL CAMINO REAL, SUITE 200
SAN DIEGO, CA 92130-2592
jleslie@luce.com

CYNTHIA WOOTEN
LUMENX CONSULTING, INC.
1126 DELAWARE STREET
BERKELEY, CA 94702
cwooten@lumenxconsulting.com

RICHARD MCCANN
M.CUBED
2655 PORTAGE BAY ROAD, SUITE 3
DAVIS, CA 95616
rmccann@umich.edu

JACK MCNAMARA
MACK ENERGY COMPANY
PO BOX 1380
AGOURA HILLS, CA 91376-1380
jackmack@suesec.com

RANDALL W. KEEN
MANATT PHELPS & PHILLIPS, LLP
11355 WEST OLYMPIC BLVD.
LOS ANGELES, CA 90064
rkeen@manatt.com

DAVID L. HUARD
MANATT, PHELPS & PHILLIPS, LLP
11355 WEST OLYMPIC BOULEVARD
LOS ANGELES, CA 90064
dhuard@manatt.com

C. SUSIE BERLIN
MCCARTHY & BERLIN LLP
100 PARK CENTER PLAZA, STE. 501
SAN JOSE, CA 95113
sberlin@mccarthylaw.com

CATHY S. WOOLLUMS
MIDAMERICAN ENERGY HOLDINGS COMPANY
106 EAST SECOND STREET
DAVENPORT, IA 52801
cswoollums@midamerican.com

THOMAS S KIMBALL
MODESTO IRRIGATION DISTRICT
1231 11TH STREET
MODESTO, CA 95352-4060
tomk@mid.org

DAVID OLIVARES
MODESTO IRRIGATION DISTRICT
PO BOX 4060
MODESTO, CA 95352
davido@mid.org

JOY A. WARREN
MODESTO IRRIGATION DISTRICT
1231 11TH STREET
MODESTO, CA 95354
joyw@mid.org

SEAN HAZLETT
MORGAN STANLEY
555 CALIFORNIA ST., SUITE 2200, 21ST FL
SAN FRANCISCO, CA 94104
sean.hazlett@morganstanley.com

NICK ALLEN
MORGAN STANLEY RESEARCH
555 CALIFORNIA STREET STE 2200
21ST FLR
SAN FRANCISCO, CA 94104
Nick.Allen@morganstanley.com

PETER W. HANSCHEN
MORRISON & FOERSTER, LLP
101 YGNACIO VALLEY ROAD, SUITE 450
WALNUT CREEK, CA 94596
phanschen@mofo.com

ROBERT J. REINHARD
MORRISON AND FOERSTER
425 MARKET STREET
SAN FRANCISCO, CA 94105-2482
rreinhard@mofo.com

JOHN DUTCHER
MOUNTAIN UTILITIES
3210 CORTE VALENCIA
FAIRFIELD, CA 94534-7875
ralf1241a@cs.com

WHITNEY BARDWICK
MP2 CAPITAL
1101 5TH AVENUE, SUITE 360
SAN RAFAEL, CA 94901

BRAD BAUER
MP2CAPITAL
1101 FIFTH AVENUE, SUITE 360
SAN RAFAEL, CA 94901
brad@mp2capital.com

MICHAEL LAINE
MP2CAPITAL
1101 5TH AVENUE, STE. 360
SASN RAFAEL, CA 94901
michael@mp2capital.com

MRW & ASSOCIATES, INC.
1814 FRANKLIN STREET, SUITE 720
OAKLAND, CA 94612
mrw@mrwassoc.com

DAVID OLIVER
NAVIGANT CONSULTING
3100 ZINFANDEL DRIVE, SUITE 600
RANCO CORDOVA, CA 95670
david.oliver@navigantconsulting.com

JOHN DALESSI
NAVIGANT CONSULTING, INC.
3100 ZINFANDEL DRIVE, SUITE 600
RANCHO CORDOVA, CA 95670-6078
jdalessi@navigantconsulting.com

KIRBY DUSEL
NAVIGANT CONSULTING, INC.
3100 ZINFANDEL DRIVE, SUITE 600
RANCHO CORDOVA, CA 95670
kdusel@navigantconsulting.com

PAUL D. MAXWELL
NAVIGANT CONSULTING, INC.
3100 ZINFANDEL DRIVE, SUITE 600
RANCHO CORDOVA, CA 95670-6078
pmaxwell@navigantconsulting.com

LAURIE PARK
NAVIGANT CONSULTING, INC.
3100 ZINFANDEL DRIVE, SUITE 600
RANCHO CORDOVA, CA 95670-6078
lpark@navigantconsulting.com

ERIN RANSLOW
NAVIGANT CONSULTING, INC.
3100 ZINFANDEL DRIVE, SUITE 600
RANCHO CORDOVA, CA 95670-6078
cpucrulings@navigantconsulting.com

KENNETH SWAIN
NAVIGANT CONSULTING, INC.
3100 ZINFANDEL DR., SUITE 600
RANCHO CORDOVA, CA 95670
kenneth.swain@navigantconsulting.com

FRED WELLINGTON
NAVIGANT CONSULTING, INC.
1 MARKET ST., SPEAR ST. TOWER, STE 1200
SAN FRANCISCO, CA 94105
fred.wellington@navigantconsulting.com

ROBERT NICHOLS
NEW WEST ENERGY
PO BOX 61868 MAILING STATION ISB 665
PHOENIX, AZ 85082-1868
rsnichol@srpnet.com

JAMES B. WOODRUFF
NEXTLIGHT RENEWABLE POWER, LLC
101 CALIFORNIA STREET, STE 2450
SAN FRANCISCO, CA 94111
jwoodruff@nextlightrp.com

KERRY HATTEVIK
NRG ENERGY
829 ARLINGTON BLVD.
EL CERRITO, CA 94530
kerry.hattevik@nrgenergy.com

HAROLD M. ROMANOWITZ
OAK CREEK ENERGY SYSTEMS, INC.
14633 WILLOW SPRINGS ROAD
MOJAVE, CA 93501
hal@rwitz.net

OCCIDENTAL POWER SERVICES, INC.
5 GREENWAY PLAZA, SUITE 110
HOUSTON, TX 77046
ej_wright@oxy.com

ANN MOORE
OFFICE OF THE CITY ATTORNEY
276 FOURTH AVENUE
CHULA VISTA, CA 91910
amoore@ci.chula-vista.ca.us

VALERIE WINN
PACIFIC GAS & ELECTRIC
77 BEALE STREET, B9A
SAN FRANCISCO, CA 94105
vjw3@pge.com

EVELYN C. LEE
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 7442
SAN FRANCISCO, CA 94120
ECL8@pge.com

BIANCA BOWMAN
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET, MAIL CODE B9A
SAN FRANCISCO, CA 94105
brbc@pge.com

CASE COORDINATION
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 770000; MC B9A
SAN FRANCISCO, CA 94177
regrelcpuccases@pge.com

LAW DEPARTMENT FILE ROOM
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 7442
SAN FRANCISCO, CA 94120-7442
cpuccases@pge.com

MATHEW A. FOGELSON
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 7442, MC B30A-2487
SAN FRANCISCO, CA 94120-7442
MAFv@pge.com

SHAUN HALVERSON
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 770000
SAN FRANCISCO, CA 94177
SEHC@pge.com

ARTHUR L. HAUBENSTOCK
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET, B30A
SAN FRANCISCO, CA 94105

NIELS KJELLUND
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET, MAIL CODE B9A
SAN FRANCISCO, CA 94105-1814
nxk2@pge.com

EDWARD V. KURZ
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE ST., B30A
SAN FRANCISCO, CA 94105
evk1@pge.com

STEPHANIE LA SHAWN
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 770000, MAIL CODE B9A
SAN FRANCISCO, CA 94177
S1L7@pge.com

GRACE LIVINGSTON-NUNLEY
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 770000 MAIL CODE B9A
SAN FRANCISCO, CA 94177
GXL2@pge.com

ED LUCHA
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 770000, MAIL CODE B9A
SAN FRANCISCO, CA 94177
ELL5@pge.com

WILLIAM V. MANHEIM
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET, ROOM 3025-B30A
SAN FRANCISCO, CA 94105
wvm3@pge.com

CORY M. MASON
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET, MC B30A
SAN FRANCISCO, CA 94105-1814
cmmw@pge.com

CHARLES MIDDLEKAUFF
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 7442
SAN FRANCISCO, CA 94120
crmd@pge.com

DAVID SAUL
PACIFIC SOLAR & POWER CORPORTATION
2850 W. HORIZON RIDGE PKWY, SUITE 200
HENDERSON, NV 89052

CATHIE ALLEN
PACIFICORP
825 NE MULTNOMAH STREET, SUITE 2000
PORTLAND, OR 97232
californiadockets@pacificorp.com

KYLE L. DAVIS
PACIFICORP
825 NE MULTNOMAH ST., 20TH FLOOR
PORTLAND, OR 97232
kyle.l.davis@pacificorp.com

RYAN FLYNN
PACIFICORP
825 NE MULTNOMAH, SUITE 1800
PORTLAND, OR 97232
ryan.flynn@pacificorp.com

CAROL A. SMOOTS
PERKINS COIE LLP
607 FOURTEENTH STREET, NW, SUITE 800
WASHINGTON, DC 20005
csmoots@perkinscoie.com

MAGGIE CHAN
PG&E
PO BOX 770000
SAN FRANCISCO, CA 94177
MMCL@pge.com

PILOT POWER GROUP, INC.
8910 UNIVERSITY CENTER LANE, STE 520
SAN DIEGO, CA 92122
tdarton@pilotpowergroup.com

THOMAS DARTON
PILOT POWER GROUP, INC.
8910 UNIVERSITY CENTER LANE, STE 520
SAN DIEGO, CA 92122
tdarton@pilotpowergroup.com

REID A. WINTHROP
PILOT POWER GROUP, INC.
8910 UNIVERSITY CENTER LANE, SUITE 520
SAN DIEGO, CA 92122
rwinthrop@pilotpowergroup.com

LISA WEINZIMER
PLATTS MCGRAW-HILL
695 NINTH AVENUE, NO. 2
SAN FRANCISCO, CA 94118
lisa_weinzimer@platts.com

THOMAS ELGIE
POWEREX CORPORATION
1400, 666 BURRAND ST
VANCOUVER, BC V6C 2X8
Tom.Elgie@powerex.com

PRAXAIR PLAINFIELD, INC.
2711 CENTERVILLE ROAD, SUITE 400
WILMINGTON, DE 19808
rick_noger@praxair.com

RICK C. NOGER
PRAXAIR PLAINFIELD, INC.
2711 CENTERVILLE ROAD, SUITE 400
WILMINGTON, DE 19808
rick_noger@praxair.com

HARVEY EDER
PUBLIC SOLAR POWER COALITION
1218 12TH ST., 25
SANTA MONICA, CA 90401
harveyederpspc@hotmail.com

TOM HAMILTON
QUALITY BUILT
15330 AVENUE OF SCIENCE
SAN DIEGO, CA 92128
thamilton@qualitybuilt.com

ERIC LARSEN
RCM INTERNATIONAL, L.L.C.
PO BOX 4716
BERKELEY, CA 94704
elarsen@rcmdigesters.com

DONALD SCHOENBECK
RCS, INC.
900 WASHINGTON STREET, SUITE 780
VANCOUVER, WA 98660
dws@r-c-s-inc.com

ARNO HARRIS
RECURRENT ENERGY, INC.
1700 MONTGOMERY ST., SUITE 251
SAN FRANCISCO, CA 94111
arno@recurrentenergy.com

JASON ABIECUNAS
RENEWABLE ENERGY CONSULTANT
11401 LAMAR
OVERLAND PARK, KS 66211
abiecunasjp@bv.com

LENNY HOCHSCHILD
RENEWABLE ENERGY MARKETS
425 MARKET STREET, SUITE 2200
SAN FRANCISCO, CA 94105
lennyh@evomarkets.com

DANIEL V. GULINO
RIDGEWOOD POWER MANAGEMENT, LLC
947 LINWOOD AVENUE
RIDGEWOOD, NJ 07450
dgulino@ridgewoodpower.com

WILLIAM P. SHORT
RIDGEWOOD POWER MANAGEMENT, LLC
947 LINWOOD AVENUE
RIDGEWOOD, NJ 07450
bshort@ridgewoodpower.com

MICHAEL DEANGELIS
SACRAMENTO MUNICIPAL UTILITY DISTRICT
6201 S STREET
SACRAMENTO, CA 95817-1899
mdeange@smud.org

ROB ROTH
SACRAMENTO MUNICIPAL UTILITY DISTRICT
6201 S STREET MS 75
SACRAMENTO, CA 95817
rroth@smud.org

WILLIAM W. WESTERFIELD III
SACRAMENTO MUNICIPAL UTILITY DISTRICT
6201 S STREET
SACRAMENTO, CA 95817
wwester@smud.org

VIKKI WOOD
SACRAMENTO MUNICIPAL UTILITY DISTRICT
6301 S STREET, MS A204
SACRAMENTO, CA 95817-1899
vwood@smud.org

CENTRAL FILES
SAN DIEGO GAS & ELECTRIC
8330 CENTURY PARK COURT, CP31E
SAN DIEGO, CA 92123
centralfiles@semprautilities.com

JENNIFER WRIGHT
SAN DIEGO GAS & ELECTRIC CO.
8330 CENTURY PARK, CT
SAN DIEGO, CA 92123
jwright@semprautilities.com

BILLY BLATTNER
SAN DIEGO GAS & ELECTRIC COMPANY
601 VAN NESS AVENUE, SUITE 2060
SAN FRANCISCO, CA 94102
wblattner@semprautilities.com

KIM F. HASSAN
SAN DIEGO GAS & ELECTRIC COMPANY
101 ASH STREET, HQ-12
SAN DIEGO, CA 92101
khassan@sempra.com

DESPINA NIEHAUS
SAN DIEGO GAS AND ELECTRIC COMPANY
8330 CENTURY PARK COURT, CP32H
SAN DIEGO, CA 92123-1530
dniehaus@semprautilities.com

THERESA L. MUELLER
SAN FRANCISCO CITY ATTORNEY
CITY HALL, ROOM 234
SAN FRANCISCO, CA 94102-4682
theresa.mueller@sfgov.org

MICHAEL A. HYAMS
SAN FRANCISCO PUBLIC UTILITIES COMM
1155 MARKET ST., 4TH FLOOR
SAN FRANCISCO, CA 94103
mhyams@sfwater.org

DAVID ORTH
SAN JOAQUIN VALLEY POWER AUTHORITY
4886 EAST JENSEN AVENUE
FRESNO, CA 93725
dorth@krcd.org

YVONNE GROSS
SEMPRA ENERGY
101 ASH STREET, HQ08C
SAN DIEGO, CA 92101
ygross@sempraglobal.com

DANIEL A. KING
SEMPRA ENERGY
101 ASH STREET, HQ 12
SAN DIEGO, CA 92101
daking@sempra.com

AIMEE M. SMITH
SEMPRA ENERGY
101 ASH STREET HQ13
SAN DIEGO, CA 92101
amsmith@sempra.com

THOMAS P. CORR
SEMPRA ENERGY GLOBAL ENTERPRISES
101 ASH STREET, HQ16C
SAN DIEGO, CA 92101
tcorr@sempra.com

LINDA WRAZEN
SEMPRA ENERGY REGULATORY AFFAIRS
101 ASH STREET, HQ16C
SAN DIEGO, CA 92101
lwrazen@sempraglobal.com

SEMPRA ENERGY SOLUTIONS
101 ASH STREET, HQ09
SAN DIEGO, CA 92101-3017
email@semprasolutions.com

GREG BASS
SEMPRA ENERGY SOLUTIONS
401 WEST BROADWAY, STE 500
SAN DIEGO, CA 92101-3017
gbass@semprasolutions.com

DANIEL M. HECHT
SEMPRA ENERGY TRADING CORP.
58 COMMERCE ROAD
STANFORD, CT 06902
dhecht@sempratrading.com

THEODORE ROBERTS
SEMPRA GLOBAL
101 ASH STREET, HQ 12B
SAN DIEGO, CA 92101-3017
troberts@sempra.com

TREVOR DILLARD
SIERRA PACIFIC POWER COMPANY
6100 NEIL ROAD, MS S4A50
RENO, NV 89520-0024
tdillard@sppc.com

ELENA MELLO
SIERRA PACIFIC POWER COMPANY
6100 NEIL RD.
RENO, NV 89511
emello@sppc.com

MARCO LEMES
SMUD
6201 S STREET MS B257
SACRAMENTO, CA 95817-1899
mlemes@smud.org

SOCAL WATER/BEAR VALLEY ELECTRIC
630 EAST FOOTHILL BLVD.
SAN DIMAS, CA 91773
kswitzer@gswater.com

KEVIN DAVIES
SOLAR DEVELOPMENT INC.
5420 DOUGLAS BLVD. STE F
GRANITE BAY, CA 95746-6253
kevin@solardevelop.com

RHONE RESCH
SOLAR ENERGY INDUSTRIES ASSOCIATION
805 FIFTEENTH STREET, N.W., SUITE 510
WASHINGTON, DC 20005

GARY L. ALLEN
SOUTHERN CALIFORNIA EDISON
2244 WALNUT GROVE AVENUE
ROSEMEAD, CA 91770
gary.allen@sce.com

FRANK W. HARRIS
SOUTHERN CALIFORNIA EDISON
2244 WALNUT GROVE
ROSEMEAD, CA 91770
frank.w.harris@sce.com

WILLIAM V. WALSH
SOUTHERN CALIFORNIA EDISON
2244 WALNUT GROVE AVE.
ROSEMEAD, CA 91770
william.v.walsh@sce.com

CASE ADMINISTRATION
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVENUE
ROSEMEAD, CA 91770
case.admin@sce.com

CATHY A. KARLSTAD
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVE.
ROSEMEAD, CA 91770
cathy.karlstad@sce.com

JAMES B. WOODRUFF
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVENUE, SUITE 342, GO1
ROSEMEAD, CA 91770

RASHA PRINCE
SOUTHERN CALIFORNIA GAS COMPANY
555 WEST 5TH STREET, GT14D6
LOS ANGELES, CA 90013
rprince@semprautilities.com

SETH D. HILTON
STOEL RIVES
111 SUTTER ST., SUITE 700
SAN FRANCISSCO, CA 94104
sdhilton@stoel.com

JANICE LIN
STRATEGEN CONSULTING LLC
146 VICENTE ROAD
BERKELEY, CA 94705
janice@strategenconsulting.com

JENNIFER CHAMBERLIN
STRATEGIC ENERGY, LLC
2633 WELLINGTON CT.
CLYDE, CA 94520
jchamberlin@strategicenergy.com

STRATEGIC ENERGY, LTD.
7220 AVENIDA ENCINAS, SUITE 120
CARLSBAD, CA 92009
customerrelations@sel.com

ELIZABETH BAKER
SUMMIT BLUE CONSULTING
1722 14TH STREET, SUITE 230
BOULDER, CO 80304
bbaker@summitblue.com

PATRICIA THOMPSON
SUMMIT BLUE CONSULTING
2920 CAMINO DIABLO, SUITE 210
WALNUT CREEK, CA 94597
pthompson@summitblue.com

JP ROSS
SUNGEVITY
1625 SHATTUCK AVE., STE 210
BERKELEY, CA 94709
jpross@sungevity.com

ED SMELOFF
SUNPOWER CORPORATION
1414 HARBOUR WAY SOUTH
RICHMOND, CA 94804
ed.smeloff@sunpowercorp.com

KEITH MCCREA
SUTHERLAND, ASBILL & BRENNAN
1275 PENNSYLVANIA AVENUE, NW
WASHINGTON, DC 20004-2415
keith.mccrea@sablaw.com

JOE GRECO
TERRA-GEN POWER LLC
9590 PROTOTYPE COURT, SUITE 200
RENO, NV 89521
jgreco@terra-genpower.com

ROBERT FINKELSTEIN
THE UTILITY REFORM NETWORK
711 VAN NESS AVE., SUITE 350
SAN FRANCISCO, CA 94102
bfinkelstein@turn.org

MARCEL HAWIGER
THE UTILITY REFORM NETWORK
711 VAN NESS AVENUE, SUITE 350
SAN FRANCISCO, CA 94102
marcel@turn.org

NINA SUETAKE
THE UTILITY REFORM NETWORK
711 VAN NESS AVE., STE. 350
SAN FRANCISCO, CA 94102
nsuetake@turn.org

MICHEL P. FLORIO
THE UTILITY REFORM NETWORK (TURN)
711 VAN NESS AVENUE, SUITE.350
SAN FRANCISCO, CA 94102
mflorio@turn.org

PETER V. ALLEN
THELEN REID BROWN RAYSMAN & STEINER
101 SECOND STREET, SUITE 1800
SAN FRANCISCO, CA 94105-3606
pvallen@thelen.com

ASHLEE M. BONDS
THELEN REID BROWN RAYSMAN&STEINER LLP
101 SECOND STREET
SAN FRANCISCO, CA 94105
abonds@thelen.com

CLIFF CHEN
UNION OF CONCERNED SCIENTISTS
2397 SHATTUCK AVENUE, STE 203
BERKELEY, CA 94708
cchen@ucsusa.org

SCOTT J. ANDERS
UNIVERSITY OF SAN DIEGO SCHOOL OF LAW
5998 ALCALA PARK
SAN DIEGO, CA 92110
scottanders@sandiego.edu

MICHAEL SHAMES
UTILITY CONSUMERS' ACTION NETWORK
3100 FIFTH AVENUE, SUITE B
SAN DIEGO, CA 92103
mshames@ucan.org

ANDREW J. VAN HORN
VAN HORN CONSULTING
12 LIND COURT
ORINDA, CA 94563
andy.vanhorn@vhcenergy.com

CHRISTOPHER O'BRIEN
VP STRATEGY AND GOVERNMENT RELATIONS
3808 ALTON PLACE NW
WASHINGTON, DC 20016
obrienc@sharpsec.com

SHERIDAN J. PAUKER
WILSON SONSINI GOODRICH & ROSATI
ONE MARKET ST
SAN FRANCISCO, CA 94105
spauker@wsgr.com

KAREN E. BOWEN
WINSTON & STRAWN LLP
101 CALIFORNIA STREET, 39TH FLOOR
SAN FRANCISCO, CA 94111
jkarp@winston.com

JOSEPH M. KARP
WINSTON & STRAWN LLP
101 CALIFORNIA STREET, 39TH FLOOR
SAN FRANCISCO, CA 94111-5894
jkarp@winston.com

DAN PERKINS
WWW.ENERGYSMARTHOMES.NET
983 PHILLIPS ST.
VISTA, CA 92083
dan@energysmarthomes.net