

CROSSBORDER ENERGY

Comprehensive Consulting for the North American Energy Industry

March 6, 2008

E-Filed

Legal Document Examiner
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Re: R. 06-02-012

Legal Document Examiner:

Enclosed for filing in the above-referenced proceeding are the original and five (5) copies of the Pre-Workshop Comments of the California Wind Energy Association, the California Cogeneration Council, and the Concentrated Solar Power Companies. Copies have been served on all parties of record in this proceeding.

As requested in the ALJ's Ruling of February 8, 2008, CalWEA / CCC / CSP have provided to the Energy Division and have posted on the CalWEA (<http://www.calwea.org/publicFilings.html>) and the CCC (<http://www.californiacogenerationcouncil.com/index.html>) websites a revised version of the MPR model that includes the changes that CalWEA / CCC / CSP have proposed for the 2008 MPR.

Thank you for your attention to this matter.

Sincerely,

R. Thomas Beach

On Behalf of the
**California Wind Energy Association, the California
Cogeneration Council, and the Concentrated Solar Power
Companies**

Enclosures

cc: All parties on Service List in R. 06-02-012

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

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

**Pre-Workshop Comments
of the California Wind Energy Association,
the California Cogeneration Council, and
the Concentrated Solar Power Companies**

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On Behalf of
**CALIFORNIA WIND ENERGY ASSOCIATION,
CALIFORNIA COGENERATION COUNCIL, and
CONCENTRATED SOLAR POWER COMPANIES**

March 6, 2008

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of the California Wind Energy Association,
the California Cogeneration Council, and
the Concentrated Solar Power Companies**

The California Wind Energy Association (CalWEA), the California Cogeneration Council, and the Concentrated Solar Power companies (CSP)¹ are pleased to present these opening, pre-workshop comments on issues associated with the 2008 market price referent (2008 MPR), as requested in Administrative Law Judge Anne Simon’s Ruling dated February 8, 2008 (ALJ Ruling) in the above-captioned proceeding. CalWEA / CCC / CSP expect to participate actively in this phase of R. 06-02-012 on matters concerning the calculation of the 2008 MPR. This proceeding will provide the first significant review of MPR issues since 2005, and there are a number of elements of the MPR calculation that need to be updated to reflect market and regulatory developments that have occurred over the last several years. CalWEA / CCC / CSP are encouraged that ALJ Simon’s comprehensive Ruling requests comments on the most important of these possible changes to the 2008 MPR, many of which CalWEA and the CCC highlighted in the prehearing conference statement that they filed on December 6, 2007.

¹ The CSP companies include Abengoa Solar, Ausra, Brightsource, Cleantech America, 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.

I. SUMMARY OF COMMENTS

CalWEA / CCC / CSP recommend that the Commission adopt the following changes to the 2008 MPR:

- **CCGT Capital Costs.** The capital costs for a new combined-cycle gas turbine (CCGT) power plant built in California should be increased to reflect the extraordinary increases in power plant construction costs that have occurred since 2005. The Brattle Group's recent survey of CCGT costs provides an index that can be used to make this adjustment. A reasonable CCGT capital cost for use in the 2008 MPR is \$1,361 per kW.
- **CCGT Capacity Factor.** The crude method now used to determine the CCGT's capacity factor should be changed to use a figure that reflects both actual capacity factors for such plants and the economics of CCGT operations in the California market. On this basis, a reasonable CCGT capacity factor is 68%.
- **TOU Factors.** The time-of-use (TOU) factors that the three investor-owned utilities (IOUs) use in their RPS RFOs and contracts are inconsistent and are not transparent. The RPS program in general would benefit from the utilities' submission of new benchmarking studies justifying their choice of TOU factors, similar to the studies that the Commission reviewed in D. 06-05-039. The Commission should direct the utilities to provide such studies.
- **MRTU Changes.** The California Independent System Operator's (CAISO) Market Re-design and Technology Update (MRTU) program will produce new, more detailed information on line losses and congestion costs at thousands of pricing points on the CAISO grid. In the future, using this new information, the MPR applicable to specific projects could be adjusted for project-specific losses and congestion, compared to system-average values. Although the implementation of MRTU has been delayed again, the upcoming workshop could begin the discussion of how MRTU values should be incorporated into the MPR.
- **System Average GMM.** Until MRTU values are incorporated into the MPR, the MPR should use the CAISO's generation-weighted system average GMM of 0.969. The simple-average GMM of 0.985 now used in the MPR significantly understates losses on the CAISO grid.
- **Fuel Price Risk Premium.** By statute, the MPR should reflect the cost of fixed-price gas, that is, of a gas supply that is not subject to fuel price volatility. The NYMEX gas futures market at the Henry Hub now reports 12 years of forward prices. All 12 years should be used in the MPR gas forecast. Beyond Year 12, the MPR gas forecast should

reflect the premium above forecasted prices that is observed in the last five years of forward market data (i.e. in Years 8 -12), as the measure of the “fuel price risk premium” associated with fixed price gas.

- GHG Adder.** The structure of the greenhouse gas (GHG) adder to the MPR that was adopted in D. 07-09-024 should be retained, and the GHG adder should become a permanent feature of the MPR. However, the GHG emission values used to calculate the 2007 GHG adder are now out-of-date, and should be updated to reflect more recent and realistic data on GHG mitigation costs. CalWEA / CCC / CSP recommend a series of GHG mitigation costs that uses current carbon dioxide (CO₂) offset prices from the European market, then increases in 2020 and 2030 to values that represent a reasonable middle ground among recent studies of the long-term costs to control GHG emissions.

Table 1 below summarizes the changes to the 2008 MPR that CalWEA, the CCC, and CSP recommend.

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	\$1,361 per kW
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 5% escalation per year	\$29 per ton CO ₂ in 2008, \$36 per ton CO ₂ in 2020, \$65 per ton CO ₂ in 2030

II. COMBINED-CYCLE CAPITAL COSTS

Issues 4.1.1 and 4.1.2

A central element of the MPR model is the estimate of the capital costs for a new CCGT power plant built in California. In past years, the MPR calculation has used the publicly-available capital costs for two CCGT plants completed in 2005 – SDG&E’s Palomar plant and

SMUD's Cosumnes unit – and then has escalated these costs to the start year for the RPS contract. Although Resolution E-4118 adopted the use in the 2007 MPR of somewhat higher construction cost escalators in determining current CCGT capital costs, CalWEA / CCC / CSP continue to be concerned that the CCGT capital costs used in the MPR model fail to reflect fully the extraordinary increases in power plant construction costs that California and the U.S. have experienced over the past several years.

The 2008 MPR model would benefit from data on the costs of new CCGTs completed after the sharp increases in construction costs experienced from 2005 to 2007. However, CalWEA / CCC / CSP are not aware that any such data is publicly available. For example, the data set used by the California Energy Commission (CEC) in its 2007 study on comparative generation costs in California is based entirely on CCGT plants completed and on-line by 2006 – a sample in which the Palomar and Cosumnes plants are among the plants completed most recently. Furthermore, the CEC simply escalates these 2001 - 2005 plant costs to 2007\$ using standard inflation indices, which do not capture the recent spike in construction costs.²

There is little doubt, however, that extraordinary increases in power plant equipment and construction costs have occurred over the last several years. The Commission is well aware that the bid prices for RPS contracts have increased significantly in the last several RPS solicitations, driven by worldwide demand for construction commodities and generation equipment such as wind turbines.³ The costs for conventional gas-fired power plants also have spiked. In August 2006, the Commission ordered Edison to build 250 MW of new simple-cycle peaking

² CEC, “Comparative Costs of California Central Station Electricity Generation Technologies” (December 2007), at 23 (Table 11); hereafter, *2007 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>.

³ The significant increases in wind turbine costs over the last several years are described in “Rising Utility Construction Costs: Sources and Impacts (Mark W. Chupka and Gregory Basheda, the Brattle Group, September 2007), hereafter, “the Brattle Study,” at 9-10 and Figures 3-4.

combustion turbines (CTs) in southern California, to meet the extraordinary demand levels reached during the late July 2006 heat wave. A simple-cycle CT is essentially the front half of a CCGT. Edison had built four 45 MW CTs by August 2007. The initial cost estimate in the fall of 2006 for these units was \$50 million per unit (\$1,111 per kW). On December 31, 2007, Edison filed for cost recovery for these four units; their final cost will be \$262 million (\$1,456 per kW), a 31% increase from the initial 2006 estimate.⁴ Although some portion of this increase may be due to the expedited schedule for these units, it is clear that the extraordinary increases in construction costs in 2006 – 2007 were far greater than what is reflected in the USACoE indices or the CEC's *2007 Generation Cost Report*.⁵ Finally, at least one new CCGT project under contract to PG&E as a result of the utility's 2006 all-source solicitation has been unable to complete development at its bid price, perhaps as a result of the unexpectedly sharp increase in equipment and construction costs during the bidding and contracting period;⁶ other generation projects contracted in recent utility solicitations have encountered similar problems.

The 2007 MPR model escalated the Palomar and Cosumnes CCGT capital costs using power plant construction cost indices published by the U.S. Army Corps of Engineers (USACoE). Based on those USACoE indices, the 2007 MPR model assumed a 16% escalation of CCGT capital costs from June 2004 to December 2007. However, other indices show a much greater escalation in power plant construction costs over that period:

⁴ See A. 07-12-029 (Edison's application for recovery of its peaker costs), at pages 2-3. This final cost represents a 31% increase from Edison's initial 2006 cost estimate of about \$50 million per peaker. See A. 07-12-029, SCE Testimony, at 27.

⁵ Table 19 of the CEC's *2007 Generation Cost Report* shows simple-cycle CT costs of \$1,053 per kW in 2007 dollars, far below what Edison actually spent. The CEC's *2007 Generation Cost Report* does not appear to have used indices beyond standard inflation indices to inflate 2001 - 2005 CCGT and CT capital costs to current dollars. CEC staff involved in the oversight of this report have confirmed this fact to us. Also see the CEC's response to PG&E's Comment 5 concerning recent construction cost escalation in Appendix C, page C-2.

⁶ CPUC Application 07-11-009; see <http://docs.cpuc.ca.gov/Published/proceedings/A0711009.htm>. A proposed decision has been issued approving the transfer of the Colusa project to PG&E.

- The Brattle Group’s recent paper on utility construction cost increases, prepared for the Edison Foundation and referenced in the ALJ Ruling, shows a 56% increase in the installed cost of new CCGT plants from 2004 to 2006.⁷ The Brattle report highlights the fact that recent federal government data from the EIA on CCGT costs have yet to recognize these extraordinary cost increases.
- Cambridge Energy Research Associates (CERA) has just announced the completion of a study finding that power plant engineering, procurement, and construction costs increased by 27% in the last year alone, with a 76% increase in construction costs over the last three years. These increases are based on CERA’s own index of power plant construction costs. CERA cites the escalation in construction commodity and labor costs, fueled by strong worldwide demand for new power plants, as the primary factor in the cost increases.⁸

In the absence of public data on the actual completion costs of new CCGT projects entering service in 2007, or expected to be completed in 2008, CalWEA / CCC / CSP recommend the use of the Brattle index on CCGT costs from 2004 - 2006 instead of the USACoE index, which results in an additional 29% increase in CCGT capital costs compared to those used in the 2007 MPR. See **Table 2**. We believe that this national index better captures the major increase in power plant capital costs than the USACoE index or the standard inflation indices used by the CEC’s *2007 Generation Cost Report*. This results in 2008 CCGT installed capital costs of \$1,361 per kW, 29% higher than the costs used to determine the 2007 MPR.

⁷ See Figures 1 and 2 on page 8 of the Brattle Study.

⁸ Dow Jones Newswires, “Power Plant Construction Costs In North America +27% In Past Year - Study” (February 14, 2008). Also, Houston Chronicle, “Power plant costs soar, hampering projects, report to say” (February 13, 2008).

Table 2: MPR Model Capital Cost Assumptions

Model	CCGT Capital Cost (\$000)	Percent Change %	Cumulative Change %	Brattle Cost Index	Percent Change %	Cumulative Change %
2004 MPR	\$720			510		
2005 MPR	\$939	30%	30%	574	13%	13%
2006 MPR	\$980	4%	36%	572	-0.3%	12%
2007 MPR	\$1,054	8%	46%	895	57%	75%
Proposed 2008 MPR	\$1,361	29%	89%			

*Note: The proposed 2008 capital cost amount is calculated as $\$1,361 = \$1,054 * (1 + 75\% - 46\%)$.*

III. COMBINED-CYCLE CAPACITY FACTOR *Issue 4.1.3*

In past years, the MPR calculation has used a relatively crude model of the dispatch of a CCGT to calculate a representative capacity factor for a CCGT plant operating in the California electric market. This model has applied each IOU's set of RPS time-of-use factors to an estimate of the MPR, to produce time-period-specific MPR prices that presumably represent market prices in an "all-in" market for both energy and capacity. The model then has assumed that the MPR CCGT unit would operate in all TOU periods in which the market price exceeded the CCGT's variable, energy-related costs. From this highly simplified model of CCGT dispatch (using just six to nine TOU periods per year), a capacity factor has been determined for each IOU's set of TOU factors. This calculated capacity factor has been used to determine a new estimate for the MPR, then the calculation has been repeated until it converged on a capacity factor. The crudeness of this approach can be seen from how variable the results have been, depending on the set of TOU factors used, as shown in **Table 3**:

Table 3: CCGT Capacity Factors Calculated by the MPR Model (%)

Utility / Year	2005	2006	2007
PG&E	81%	80%	87%
Edison	92%	64%	62%
SDG&E	92%	92%	95%
Average	88%	79%	76%

Source: 2005 - 2007 adopted MPR models. Note that in 2005 and 2006, a simple average of the three calculated capacity factors was used; in 2007, Resolution E-4118 changed to an average weighted by utility sales.

There are substantial differences between the TOU factors of the three IOUs, even though the three utilities operate in the same or closely related wholesale markets. As shown in Table 3, the differences in TOU factors produce substantially different CCGT capacity factors under the calculation method used in the MPR model. A further problem has been the IOUs' reluctance to reveal the details of the development of their TOU factors. Over the last several months, the RPS TOU factors have been under scrutiny in the Commission's ongoing qualifying facility (QF) proceeding (R. 04-04-025), in which the Commission has adopted, for use in QF energy pricing, TOU factors "consistent with" the RPS factors used in the MPR model.⁹ In the QF proceeding, the IOUs have not been willing to provide other parties with the full details of how their TOU factors are derived. Those details might allow a better understanding of the differences between the IOUs' inconsistent sets of TOU factors.

One of the few details concerning the IOUs' TOU factors that has come to light in the QF proceeding is the fact that SDG&E's RPS TOU factors are energy-only factors, not factors that combine both energy and capacity values.¹⁰ Because SDG&E's TOU factors are energy-only, when applied to the "all-in" MPR price, they produce off-peak market prices that clearly are too

⁹ D. 07-09-040, at 74-75.

¹⁰ SDG&E Advice Letter 1952-E, at pages 8 and 9: "SDG&E's MPR TOD factors are appropriate for an energy market application because they do not include an additional capacity cost component."

high, resulting in excessive dispatch of the CCGT and a too-high CCGT capacity factor, as the results in Table 3 illustrate. Thus, SDG&E's RPS TOU factors clearly are inappropriate for calculating CCGT dispatch based on the "all-in" MPR price.

The Commission should address the current inconsistencies and lack of transparency in the three different sets of time-of-use factors used in the MPR model and in the utilities' RPS solicitations. The Commission presently allows each utility to propose its own set of TOU factors in its RPS Request for Offers (RFO); these also are the TOU factors used in the MPR model. CalWEA / CCC / CSP do not necessarily oppose any of the current sets of TOU factors used in the MPR model, but observe that the substantial differences between the TOU factors of the three IOUs do not make much sense, given that the three utilities operate in the same or closely related wholesale markets. In past years, these differences have had a significant impact on the MPR model's calculation of the CCGT capacity factor. In 2005, the Commission required the utilities to submit benchmarking studies justifying their choice of TOU factors for their RPS RFOs (D. 05-12-042, at 22), then the Commission reviewed and approved those studies and factors in D. 06-05-039 (at 66-73). Even though CalWEA / CCC / CSP recommend below a method to determine the CCGT capacity factor that does not use TOU factors, we believe that the RPS program in general would benefit from the utilities' submission of new benchmarking studies justifying their choice of TOU factors. The Commission should direct the utilities to submit such studies.¹¹

CalWEA / CCC / CSP have examined a number of other sources and options for representative capacity factors for CCGT plants operating in California. These include:

- **Actual capacity factors** from CCGT plants operating in California in recent years are summarized in Table 30 of the CEC's *2007 Generation Cost Report*. We recommend some caution in the use of this data, as the operating hours for an individual CCGT may

¹¹ It is absolutely imperative that the utilities submit new TOU benchmarking studies, if the Commission decides to retain the current iterative method of using the IOUs' TOU factors to determine the CCGT capacity factor.

depend on whether or not it is under a long-term contract, or must sell on a short-term basis into the California wholesale electric market. For example, some of the CCGTs in the CEC's sample may operate at relatively high capacity factors in support of long-term, must-take Department of Water Resource contracts signed in 2001. Based on the data available, the CEC's *2007 Generation Cost Report* concludes that 60% is a representative capacity factor for operating CCGTs in California.¹²

- **CAISO Annual CCGT Calculations.** Every year since 2003, the California Independent System Operator (CAISO) has published in its *Annual Report on Market Issues and Performance* a calculation of a representative capacity factor for a new CCGT, based on CAISO market prices from the year covered by the report. The CAISO's calculated CCGT capacity factors have been relatively constant over the 2003 - 2006 period, with the NP-15 capacity factor ranging from 63% to 69% (average 66%) and the SP-15 capacity factor ranging from 72% to 75% (average 73%). The calculated statewide average CCGT capacity factor over the period is 69.5%. We note that 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.¹³
- **Calculated 2007 CCGT Capacity Factors.** We have performed our own calculations of the CCGT capacity factor based on 2007 daily on- and off-peak electric market prices in the day-ahead market and daily burner-tip natural gas prices in the NP-15 and SP-15 markets, thus extending the CAISO calculations to 2007. We have assumed 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. Our calculated CCGT capacity factors for 2007 are 65% for NP-15 and 71% for SP-15, with a statewide average of 68%.

Based on the analyses presented above, CalWEA / CCC / CSP believe that a representative CCGT capacity factor in the California market falls in the range of 60% to 75%, and recommend the use of 68% for the 2008 MPR, based on our calculated CCGT capacity factor using 2007 market prices. We believe that the approach described above, which considers both real-world operating history and analyses using actual California market prices, provides a more

¹² CEC, *2007 Generation Cost Report*, at 55 and Table 25.

¹³ CAISO, *2006 Annual Report on Market Issues and Performance*, at Chapter 2, pages 2.51-2.56 and Table 2.11. This report is available at <http://www.caiso.com/1b7e/1b7e71dc36130.html>.

realistic approach to determining the CCGT capacity factor than the very rough and volatile calculation that has been used in the MPR model since 2005.

IV. MRTU AND TRANSMISSION ISSUES

Issue 4.1.4

A. MRTU Issues

The ALJ Ruling asks parties to comment on whether, when, and how the CAISO's Market Re-design and Technology Update (MRTU) program might impact the 2008 MPR calculation. As a threshold matter, it is now clear that MRTU will not "go live" on April 1, 2008. We are not aware of a new "go live" date. It is very possible that MRTU may not become reality soon enough for the new market data that it will provide to impact the 2008 MPR determination. Furthermore, the Commission should provide an opportunity to make certain that MRTU is functioning properly, before its market data is incorporated into benchmarks such as the MPR. 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.¹⁴ However, CalWEA / CCC / CSP believe that it would be useful to explore at the workshop and in post-workshop comments how MRTU prices, once they are functioning properly, might be used to bring greater locational specificity to MPR prices.

B. The GMM-based Line Loss Factor for the 2008 MPR

The MPR model uses a CAISO 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. However, actual CAISO system average transmission lines losses are 3.1%.¹⁵ What is the cause of this discrepancy?

¹⁴ D. 07-09-040, at 67-68.

¹⁵ CAISO Oasis data for each month in 2007. This CAISO data compares total system losses to actual system loads. See <http://oasis.caiso.com/>.

The problem with the GMM used in the MPR model is that it is the simple average of all the GMMs on the CAISO system; the average is not weighted by the amount of power that is produced at each generator for which the CAISO calculates a GMM. The MPR model uses a simple average GMM taken from the QF line loss formula adopted in D. 01-01-007. The use of a simple average GMM weights all generators equally, regardless of size. A 5 MW QF in the load center is assumed to have the same impact on overall losses as a very large, 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 thus understates 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.

CalWEA / CCC / CSP recommend that the 2008 MPR should use a GMM-based line loss factor that reflects the weighted average of GMMs on the CAISO grid. The current use of the simple average GMM is simply wrong, as explained above, and should be revised to 0.969, reflecting full system average losses on the CAISO grid in 2007, as shown in **Table 4**.

Table 4: CAISO Load and Losses in 2007 (MW)

<u>Month</u>	<u>Load</u>	<u>Losses</u>	<u>As Percent</u>
Jan-07	26,548	837	3.2%
Feb-07	25,536	794	3.1%
Mar-07	25,744	824	3.2%
Apr-07	25,604	786	3.1%
May-07	27,226	811	3.0%
Jun-07	28,886	836	2.9%
Jul-07	31,868	931	2.9%
Aug-07	32,848	975	3.0%
Sep-07	29,166	912	2.9%
Oct-07	26,104	792	3.0%
Nov-07	25,436	830	3.3%
Dec-07	26,160	814	3.1%
2007 Average	27,594	845	3.1%

Ultimately, the MPR applicable to a specific generator could be adjusted to reflect losses and congestion at the generator’s node on the CAISO system, compared to system-average or utility-average values. However, as discussed above, even if MRTU “goes live” in 2008, there will need to be a “probationary” period to ensure that the MRTU markets are working well, before those market values are used as part of the MPR. This means that the GMM-based line loss factor of 0.969 should be used with the 2008 MPR.

V. FUEL PRICE RISK PREMIUM

Issue 4.2.1

The ALJ Ruling asks parties to comment on the CEC’s discussion, in its *2007 Integrated Energy Policy Report (2007 IEPR)*, on whether the MPR should include a “fuel price risk premium” that reflects the cost of natural gas price volatility. The RPS statute provides that the

MPR should represent the cost of a new generating facility with a fixed-price fuel contract.¹⁶ In other words, the MPR should reflect the all-in costs of a new CCGT from which all fuel price volatility has been removed through a fixed-price natural gas contract. CalWEA / CCC / CSP 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 CEC's 2007 IEPR presented modeling results suggesting that, if the 2006 MPR model were adjusted to remove the risks of fossil fuel price volatility, the model would produce an MPR 13% to 17% higher than the actual 2006 MPR.¹⁷ CalWEA / CCC / CSP have been unable to verify the CEC consultant's results,¹⁸ but agree that the current MPR model fails to reflect fully the costs of eliminating all fuel price volatility over the entire term of 10- to 20-year RPS contracts. As a result, the Commission should revise the 2008 MPR to reflect fully the costs of mitigating fuel price risk.

To accomplish this, we recommend several simple changes to the MPR gas price forecast. First, NYMEX recently has extended its public series of Henry Hub natural gas forward prices from six years forward to twelve years forward. Thus, forward Henry Hub prices are now available through 2020. This extension provides six more years of visible price data on the cost of a fixed-price natural gas supply. For the remaining years 13 - 30 of the long-term gas forecast, we recommend that the Commission add a premium to the fundamentals forecast that reflects any observed premium in the forward market, above the fundamentals forecast, over the last five

¹⁶ P.U. Code Section 399.15(c) 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."

¹⁷ California Energy Commission, *2007 Integrated Energy Policy Report* (adopted December 5, 2007; CEC Publication CEC-100-2007-008-CTF), at 181 - 183, especially Tables 4-9, 4-10, and 4-11, available at http://www.energy.ca.gov/2007_energypolicy/index.html.

¹⁸ The CEC consultant uses the concepts of the Capital Assets Pricing Model to argue that the premium associated with fuel price volatility should be incorporated into the MPR model through the use of a risk-free discount rate. The CEC CalWEA / CCC / CSP have been unable to duplicate the CEC consultant's results simply through the use of a risk-free discount rate of about 5% in the 2006 MPR model (compared to the original discount rate of about 9%)..

years for which forward market data is available (i.e. years 8 - 12). Forward natural gas prices have shown a consistent premium over contemporaneous fundamental forecasts, which strongly suggests that there is a risk premium associated with eliminating gas price volatility by fixing the price. If such a premium exists during the initial twelve years of the MPR gas forecast, it should be assumed to persist for the remainder of the forecast period. Indeed, a Lawrence Berkeley National Lab (LBNL) study, ongoing since 2003, has compared natural gas forward prices to contemporaneous spot price forecasts. LBNL has observed that forward prices consistently exceed contemporaneous forecasts of expected spot prices, perhaps as a result of the risk premium associated with fixed-price gas supplies.¹⁹ This study has been examined in prior phases of this case, and D. 03-06-071 concluded that such costs to eliminate the risks of volatile fossil fuel prices were real and should be included in the MPR gas forecast methodology.²⁰

VI. GREENHOUSE GAS ADDER *Issue 4.3*

D. 07-09-024 adopted the use of a greenhouse gas (GHG) adder in calculating the 2007 MPR, but made clear that the authorization for a GHG adder was limited to the 2007 MPR.²¹ The GHG adder included in the 2007 MPR is based on a series of GHG mitigation costs approved by the Commission in D. 04-12-048 (\$8 per ton CO₂ in 2004, escalating at 5% per year). The calculation of the 2007 GHG adder assumes that a new CCGT plant would not bear such costs until 2012, the year in which the state must implement its permanent program for regulating GHG

¹⁹ 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>.

²⁰ See D. 03-06-071, at 22-23 and Finding of Fact 17.

²¹ D. 07-09-024, at 7, 9, and Ordering Paragraph 2.

emissions. CalWEA / CCC / CSP 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. However, the GHG emission values used to calculate the 2007 GHG adder are now out-of-date, and should be updated to reflect more recent and realistic data on GHG mitigation costs. Realistically, the GHG emission values used in the GHG adder will change over time, and may need further revision in the future, as the AB 32 regulatory program is developed and implemented. For the 2008 GHG adder, we recommend below an increase in the assumed costs to mitigate the GHG emissions of a new CCGT, compared to the outdated series of GHG mitigation costs used with the 2007 MPR.

As the Commission is well aware, the central task for 2008 in implementing AB 32 will be the development and approval by the California Air Resources Board (CARB) of a comprehensive scoping plan for how the state will meet the AB 32 goal of reducing GHG emissions to 1990 levels by 2020. This plan is unlikely to be adopted until late in 2008. As a result, the GHG adder for the 2008 MPR undoubtedly must continue to be an interim value, and the Commission may not be able to develop in this proceeding the “comprehensive and permanent change to the MPR methodology to include a GHG adder” that is suggested in the ALJ Ruling. The MPR adopted in 2008 and future years should include a GHG adder, but the value of that adder should be subject to further refinement as more decisions are made and more details become available on the structure of the AB 32 program. For example, if the state proceeds to implement a cap-and-trade program to regulate GHG emissions, that program will become a logical source for the economic value of reducing GHG emissions in California. Ultimately, there may be a national or even international cap-and-trade program to regulate GHG emissions, in which California will participate. However, GHG mitigation values from such a program obviously will not be available to inform the development of the GHG adder for the 2008 MPR.

The GHG emissions costs now included in the 2007 GHG adder were developed in 2004 by the E3 consulting firm in its report to the Commission on the avoided costs associated with

energy efficiency programs.²² In that report, E3 reviewed modeling work on reaching the CO₂ emission targets under the Kyoto Protocol and limited data from the initial efforts in European Union (EU) countries to trade carbon offsets. The GHG mitigation costs that the E3 Report recommended and the Commission adopted are \$8 per ton of CO₂ in 2004, escalating at 5% per year, or \$9.72 per ton of CO₂ in 2008. E3 chose these values from the low end of the spectrum of GHG emission costs that it examined, and characterized them as “reasonable and conservative, albeit uncertain.”²³ Today, much broader, market-based measures of GHG mitigation costs are available, such as the prices in the EU’s active carbon offset market, the world’s largest. Since January 2006, EU carbon offset prices for 2008 have ranged from \$16 to \$39 per metric ton (\$14 to \$36 per short ton), and recent forward prices for 2008 have averaged \$29 per short ton.²⁴ In 2006, the worldwide carbon market traded 1.6 billion metric tons of CO₂ allowances, at an average price of about €14.06 per metric ton (\$16.05 per short ton); in 2005, the average carbon price was €11.76 per metric ton (\$12.27 per short ton).²⁵ All of these market values are well above the E3 GHG mitigation costs used in the 2007 GHG Adder.

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 offset market in the world – for data on the current costs of mitigating

²² “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.

²³ *Ibid.*, at 89.

²⁴ 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.

²⁵ See “Carbon 2007” from Point Carbon, available at http://www.pointcarbon.com/getfile.php/fileelement_105366/Carbon_2007_final.pdf.

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 CO₂ that the Commission adopted in D. 04-12-048. 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. Furthermore, a current GHG mitigation cost in the range of \$20 to \$40 per short ton is reasonable given the costs of other important “early action” measures already taken by this Commission and the CARB, as well as GHG offset values from the voluntary market, such as PG&E’s CPUC-approved ClimateSmart program. **Table 5** provides a summary of such “early action” GHG mitigation costs.

Table 5: GHG Early Action Measures and Costs

Early Action Measure	Cost (\$ per ton CO ₂)	Sources
SB 1368 Emission Performance Standard (EPS), limiting GHG emissions from new baseload resources to 1,100 lbs/MWh.	\$20 - \$60	D. 07-01-039. Cost difference between natural gas and coal generation (\$15 to \$30 per MWh), divided by the CO ₂ emissions difference between coal and natural gas (0.5-0.75 tons / MWh).
Reduction in HFC-134a from auto air conditioners	\$12 - \$40 ²⁶	Adopted by CARB in January 2007.
PG&E ClimateSmart, voluntary carbon neutrality	\$19 - \$23	D. 06-12-032. Program costs are \$37 to \$46 million (including market and administration) for CO ₂ reductions of 2 million tons.

In taking these early action measures, California has signaled that, in the words of the Commission in adopting the SB 1368 EPS in D. 07-01-039, the state has “raised the bar” in its GHG mitigation actions.²⁷ Given these recent actions to “raise the bar,” the outdated 2004 GHG mitigation values now used in the 2007 MPR’s GHG adder also should be raised.

²⁶ CARB, “Expanded List of Early Action Measures to Reduce Greenhouse Gas Emissions in California Recommended for Board Consideration” (October 2007), at 12 and B-7.

²⁷ D. 07-01-039, at 34.

In the long-run, 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.²⁸ Synapse used this work to prepare low, medium, and high projections for GHG mitigation costs in 2020 and 2030, as shown in **Table 6**. Synapse presented its results in 2005\$; we present nominal values assuming 2.5% annual inflation.

Table 6: *Synapse GHG Mitigation Cost Forecasts for 2020 and 2030*
(Nominal \$ per ton CO₂)

Year / Case	Low	Medium	High
2020	\$14	\$36	\$58
2030	\$37	\$65	\$93

Our recommended projection of future GHG mitigation costs uses current EU carbon prices of \$29 per ton for 2008, then increasing over time to Synapse’s medium projections for 2020 (\$36 per ton) and 2030 (\$65 per ton). **Figure 1** provides a summary of the current E3 GHG emission costs, the Synapse projections, current EU carbon offset trading prices, and our recommended forecast of GHG mitigation costs.

VII. UPDATES TO THE MPR INPUT ASSUMPTIONS

As the Commission has done with each year’s MPR, the Commission should update the input assumptions to the MPR model, to the extent that new or updated information is available. In addition to the assumptions discussed in these comments, the input values that may be updated annually include the heat rate, O&M costs, and financing assumptions for a new CCGT,

²⁸ 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>.

as well as long-term natural gas commodity and transportation costs.

VIII. IMPACT OF PROPOSED CHANGES TO THE 2008 MPR

CalWEA / CCC / CSP summarize in **Table 7** their recommended changes to the 2008 MPR calculation, compared to the input values and calculation methods used with the 2007 MPR.

Table 7: 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	\$1,361 per kW
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 5% escalation per year	\$29 per ton CO2 in 2008, \$36 per ton CO2 in 2020, \$65 per ton CO2 in 2030

We have provided to the Energy Division and posted on CalWEA’s and the CCC’s websites²⁹ 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 from February 20, 2008.

IX. THE MPR MODEL SHOULD BE EXTENDED TO INCLUDE RPS CONTRACTS WITH TERMS OF UP TO 30 YEARS.

²⁹ <http://www.calwea.org/publicFilings.html> and <http://www.californiacenerationcouncil.com/index.html>.

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 term. CalWEA / CCC / CSP believe that longer RPS contract terms would help to moderate future RPS bids. Renewable projects are capital-intensive endeavors, with most of the costs expended at the outset of the project. The annual revenue requirement for the project – and thus the price that is bid into the RPS solicitation and that ratepayers pay – can be reduced if the term of the power sales contract is longer and the financing for the project can be extended over more years. California has many examples of solar thermal, wind, geothermal, and biomass projects developed in the 1980s under 30-year QF contracts that have operated successfully for almost 25 years and that promise to operate to and beyond the initial 30-year term of their contracts. Accordingly, the Commission should consider requiring the utilities to offer RPS contracts with terms of 25 or 30 years. CalWEA / CCC / CSP recognize that these MPR comments are not the right forum in which to request such a change to the RPS program; however, we expect to pursue this issue soon via the appropriate procedural vehicle. The Commission’s 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.

X. CONCLUSION

CalWEA / CCC / CSP appreciate the Commission’s willingness to review in detail the 2008 MPR calculation. As set forth above, there are a number of aspects of the MPR determination that need to be updated to reflect today’s realities. CCGT capital costs need to reflect the rapid escalation in power plant construction and equipment costs from 2005 - 2007. The CCGT capacity factor must reflect the reality of CCGT operations and economics in the California market. The MPR line loss adjustment must be based on the weighted average of CAISO GMMs. The GHG adder should become a permanent feature of the MPR; the GHG emission costs used in the adder should reflect current values from the EU carbon market, the

world's largest and broadest such market, and from California's own "early action" measures. In the longer-term, the Commission should look to long-term projections that incorporate the growing range of modeling efforts on GHG mitigation costs. With these changes, CalWEA, the CCC, and CSP believe that the 2008 MPR will fulfill more accurately its statutory role of reflecting the full costs of conventional generation in California, including the cost impacts of volatile fossil fuel prices and the GHG emissions from burning natural gas.

We recognize that the recommendations presented above would result in a significant increase in the 2008 MPR, compared to the 2007 value. Such an increase is fully justified based on the reasons set forth above, including rapidly increasing construction costs for conventional power plants and the most recent information on the likely costs of GHG mitigation. As the Commission is well aware, the worldwide demand for construction commodities and energy production equipment also is pushing RPS bids higher. The MPR needs to be adjusted to reflect this trend to higher costs for both renewable and conventional generation, so that the limited pool of above-market funds for the RPS program is not exhausted on RPS bids that exceed an MPR that does not reflect fully the costs of conventional gas-fired generation.

We look forward to participating actively in the upcoming workshop that will discuss these issues in more detail, and in subsequent comments on these important refinements to the MPR calculation.

Respectfully submitted,

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On Behalf of
**CALIFORNIA WIND ENERGY ASSOCIATION,
CALIFORNIA COGENERATION COUNCIL, and
CONCENTRATED SOLAR POWER COMPANIES**

March 6, 2008

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused to be served a copy of the foregoing document, **Pre-Workshop Comments of the California Wind Energy Association, the California Cogeneration Council, and the Concentrated Solar Power Companies**, 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, Thursday, March 6, 2008.

/signed/

Christa Goldblatt