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Decision 05-12-042 December 15, 2005

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement the California Renewables Portfolio Standard Program.	Rulemaking 04-04-026 (Filed April 22, 2004)

INTERIM OPINION ADOPTING METHODOLOGY FOR 2005 MARKET PRICE REFERENT

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INTERIM OPINION ADOPTING METHODOLOGY FOR 2005 MARKET PRICE REFERENT

I. Summary

We adopt the methodology for calculating the 2005 market price referent (MPR) to be used for solicitations in the Renewables Portfolio Standard (RPS) program. We direct Energy Division staff to calculate the 2005 MPR, to be applied to the 2005 solicitations that we approved in Decision (D.) 05-07-039, based on this methodology.

II. Procedural Background

On June 19, 2003, we issued D.03-06-071, which provided guidance on a range of RPS issues, including development of an MPR methodology.[1] On June 9, 2004, we issued D.04-06-015, which adopted a cash-flow simulation methodology to calculate MPRs, and determined that MPRs will be publicly disclosed to all parties simultaneously, after utilities' RPS solicitations have closed, but before advice letters requesting contract approval are filed. On July 8, 2004, we issued D.04-07-029, which described the RPS solicitation – contract approval schedule, including the process for calculating and releasing the MPR; detailed how the MPR would be used in the bid evaluation process; and outlined the California Energy Commission's (Energy Commission) Supplemental Energy Payment (SEP) process.

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[1] This was in compliance with the Legislature's instruction in Pub. Util. Code § 399.14(a)(2)(A) that certain methods and processes for the RPS program be adopted within six months of the January 1, 2003 effective date of the RPS legislation, Senate Bill (SB) 1078 (Sher). All subsequent references to sections are to the Public Utilities Code unless otherwise specified.

Pursuant to D.04-06-015, an Assigned Commissioner's Ruling (ACR) and associated staff report was issued on February 4, 2005, which publicly disclosed the 2004 MPRs.[2] Parties filed comments and reply comments. After staff review of the comments, we adopted Resolution E-3942 on July 21, 2005, which disclosed the final 2004 MPR values for baseload and peaking proxy plants.

A prehearing conference (PHC) was held May 18, 2005, to address issues related to the calculation and adoption of the 2005 MPR, including modifications to the existing 2004 MPR methodology; a methodology for applying Time of Delivery (TOD) profiles to the 2005 MPR; and gas and non-gas inputs for the 2005 MPR. Based on the consensus reached at the PHC, an Administrative Law Judge's (ALJ) Ruling dated May 24, 2005, asked the parties to file separate pre-workshop comments for two proposed MPR workshops: one covering gas and non-gas inputs, gas forecast modeling, and the cash flow model adopted for the 2004 MPR; and one covering TOD profiles.[3] The gas/non-gas workshop and TOD workshop were held on June 20-21, 2005 and June 27-28, 2005, respectively.

After these workshops, an ALJ Ruling dated July 7, 2005 asked parties to file post-workshop comments to address a series of questions regarding gas/non-gas inputs, 2005 MPR methodology, and the MPR TOD methodology.

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2 On February 7, 2004, it came to staff's attention that there had been a technical error in the MPR calculation. The technical error was corrected and the revised 2004 MPRs and staff report were reissued in an ACR on February 11, 2004.

3 Pre-workshop comments were filed on June 10, 2005, by the California Cogeneration Council, California Wind Energy Association (CalWEA), and California Biomass Energy Alliance jointly (CalWEA group); Green Power Institute (Green Power); Pacific Gas and Electric Company (PG&E); Southern California Edison Company (SCE); San Diego Gas & Electric Company (SDG&E); Solargenix; and Union of Concerned Scientists (UCS).

Footnote continued on next page

Parties filed comments on August 5, 2005[4] and reply comments on August 16, 2005[5]. In addition to extensive comments filed by the parties, a number of documents were circulated to the parties and presentations were made at the workshops and in subsequent working group meetings by parties, by staff, and by Energy and Environmental Economics, Inc. (E3),[6] consultants to staff.

III. Discussion

A. Foundations of the MPR

The MPR is a key component of the RPS program. In setting up the RPS program, the Legislature assigned three functions to the MPR. The first, expressed in § 399.14(f), is to deem reasonable per se and allow to be recovered in rates those "[p]rocurement and administrative costs associated with long-term contracts entered into by an electrical corporation for eligible renewable energy resources pursuant to this article, at or below the market price determined by the commission pursuant to subdivision (c) of Section 399.15. . ."[7]

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[4] Comments were filed by jointly by CalWEA group; Green Power; Office of Ratepayer Advocates (ORA); PG&E; SDG&E; SCE; Solargenix; The Utility Reform Network (TURN), and UCS.

[5] Reply comments were filed by the CalWEA group, Green Power, ORA, PG&E, SDG&E, SCE, and TURN.

[6] Information about E3 may be found at its web site, http://www.ethree.com.

[7] We decided in D.04-06-015 that the contract price must be calculated on a net present value basis over the entire contract term.

The second function of the MPR is to establish the basis for the use of SEPs, which are awarded by the Energy Commission. Pub. Res. Code § 25743(b)(1) provides that:

> In order to cover the above market costs of renewable resources as approved by the Public Utilities Commission and selected by retail sellers to fulfill their obligations under Article 16 (commencing with Section 399.11) of Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code, the [energy] commission shall award funds in the form of supplemental energy payments, subject to. . . criteria. . .

See also §§ 399.15(a)(2)[8] and 399.13(c).[9] In order to carry out this function, we concluded in D.04-06-015 that the contract price should be compared to the MPR on a net present value basis as calculated over the entire contract term.

The third function of the MPR is to set limits on certain obligations of retail sellers under the RPS program. One obligation so limited is the obligation to buy energy from renewable resources. As provided in § 399.15(a)(1), "[a]n electric corporation shall not be required to enter into long-term contracts with eligible renewable energy resources that exceed the market prices established

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[8] Sec. 399.15(a) provides that the Energy Commission "shall provide supplemental energy payments from funds in the New Renewable Resources Account in the Renewable Resource Trust Fund to eligible renewable energy resources pursuant to Chapter 8.6 (commencing with Section 25740) of Division 15 of the Public Resources Code, consistent with this article, for above-market costs."

[9] Sec. 399.13(c) provides that the Energy Commission shall. . . "[a]llocate and award supplemental energy payments pursuant to Chapter 8.6 (commencing with Section 25740) of Division 15 of the Public Resources Code, to eligible renewable energy resources to cover above-market costs of renewable energy."

pursuant to subdivision (c) of this section." A related limit is established by § 399.15(b)(4):

> If supplemental energy payments from the Energy Commission, in combination with the market prices approved by the commission, are insufficient to cover the above-market costs of eligible renewable energy resources, the commission shall allow an electrical corporation to limit its annual procurement obligation to the quantity of eligible renewable energy resources that can be procured with available supplemental energy payments.

To establish the market price necessary for implementation of the RPS program, the Legislature directed us (in consultation with the Energy Commission) to:

> Establish a methodology to determine the market price of electricity for terms corresponding to the length of contracts with renewable generators, in consideration of the following:
>
> (1) The long-term market price of electricity for fixed price contracts, determined pursuant to the electrical corporation's general procurement activities as authorized by the Commission.
>
> (2) The long-term ownership, operating, and fixed-price fuel costs associated with fixed-price electricity from new generating facilities.
>
> (3) The value of different products, including baseload, peaking, and as-available output. (Pub. Util. Code § 399.15(c).)

In D.04-06-015, we clarified "what the MPR is not: it does not represent the cost, capacity or output profile of a specific type of renewable generation technology. . . [T]he MPR is to represent the presumptive cost of electricity from a non-renewable energy source, which this Commission, in D.03-06-071, held to be a natural gas-fired baseload or peaker plant." (D.04-06-015, *mimeo.*, p. 6, n.10.)

In D.03-06-071, we determined that it was not feasible to employ the first consideration set out in § 399.15(c), "the long-term market price of electricity for fixed price contracts, determined pursuant to the electrical corporation's general procurement activities." Because the existing long-term contracts for electricity were almost exclusively those signed by the Department of Water Resources (DWR) pursuant to Water Code § 80100 *et seq.*, we concluded that there were not a sufficient number of existing, reasonably-priced, long-term power contracts of recent vintage currently in the utilities' resource portfolios to establish an MPR based on the first consideration. We therefore relied on the second and third considerations, developing a proxy plant to model the long-term costs "associated with fixed-price electricity from new generating facilities," taking into account "the value of different products, including baseload, peaking, and as-available output." As long as the DWR contracts remain the dominant long-term electricity procurement contracts, we will use the proxy plant method to calculate the MPR.[10]

B. Purpose of this Decision

With this decision, we reaffirm the basic structure of the MPR methodology developed in 2004, while making improvements that will complete the MPR methodology. We seek a method that is reasonably stable, is reasonably transparent (*i.e.*, participants can understand the choices made), and that has inputs that are readily available and subject to relatively easy

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[10] Documents submitted by DWR in Application (A.) 00-11-038 *et al*. show that DWR contracts account for approximately 30% of the utilities' load.

verification. To accomplish these goals, we seek to maximize the use of internally consistent assumptions, data, and inputs.

Our evaluation of competing proposals is guided by looking to the behavior of participants in the California market for power purchase agreements (PPAs) for electricity from new gas-fired generation. We take this approach because, based on the parties' extensive written submissions and discussion at the workshops, adopting the perspective of market participants is most likely to result in an MPR methodology that is a reasonably accurate model for the market price of electricity in a 20-year contract. We recognize that it is not always possible to know fully the behavior of market participants, but the effort to do so provides a consistent and transparent basis for making choices about methodology and inputs that are subject to legitimately differing views.

We examine two categories of changes to the MPR method: those that we suggested in 2004 that parties might pursue in 2005, and those that party comments have brought to our attention in the 2005 MPR process. We also undertake refinement of some of the inputs to the MPR model.

C. MPR Gas Forecasting Inputs and Methodology

Approximately 75% of the lifetime cost of a gas-fired combined cycle plant is the cost of the natural gas fuel. The estimation of gas costs is therefore a particularly important part of the MPR calculation. As we noted in D.04-06-015, however, there is no transparent, liquid market for natural gas forward products for 10-, 15- or 20-year terms, to use as the basis to fuel a proxy power plant producing fixed-priced electricity over these time periods. Consequently, D.04-06-015 outlined a California gas forecasting methodology that used one method for Years 1 through 6, and another for Years 7 through 20 of a hypothetical 20-year PPA for the proxy plant. Both are based on the forward Henry Hub gas price that is basis adjusted to California.[11]

D.04-06-015 determined that NYMEX Henry Hub futures price would be used for all or part of the first six years of the gas forecast. For Years 7-20, a fundamentals forecast approach would be used, incorporating the forecast escalation methodology advocated by several parties. This method entails calculating the average annual escalation rate among a number of different long-term Henry Hub forecasts, including public forecasts by the Energy Information Administration (EIA) of the federal Department of Energy[12] and the Energy Commission[13] and proprietary forecasts by Cambridge Energy Research Associates (CERA),[14] PIRA Energy Group (PIRA),[15] and Global Insight.[16] This average annual escalation rate would then be used to escalate the last year of NYMEX data out to 2024, the 20-year term of the proxy plant's PPA. In addition, a gas hedging transaction cost would be added to both the NYMEX and fundamental gas prices. Using this methodology, parties worked collaboratively

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[11] "The Henry Hub is the largest centralized point for natural gas spot and futures trading in the United States. The New York Mercantile Exchange (NYMEX) uses the Henry Hub as the point of delivery for its natural gas futures contract." http://www.eia.doe.gov/oiaf/analysispaper/henryhub/.

[12] Information about EIA may be found at http://www.eia.doe.gov/.

[13] No current long-term gas forecast by the Energy Commission is available for the 2005 MPR.

[14] Information about CERA may be found at http://www.cera.com/home/.

[15] Information about PIRA may be found at http://www.pira.com/default.htm.

[16] Information about Global Insight may be found at http://www.globalinsight.com/.

to develop the MPR gas model[17] used to calculate the MPRs presented in the February 10, 2005, Revised 2004 Market Price Referent (MPR) Staff Report.

We are revisiting the 2004 gas model for two principal reasons. First, in 2004, SCE proposed a different model, referred to as the "cost of carry" model, for gas prices in Years 7-20 of the proxy plant PPA. In D.04-06-015, we concluded that SCE had not presented this model in sufficient detail to allow us to decide whether to adopt it. We suggested that SCE could do so in 2005. SCE has made a detailed presentation, to which parties have responded in some detail, so we now review the SCE "cost of carry" proposal. Second, parties have criticized the model used in 2004 as not yielding consistent and explainable results using data from a variety of time periods and market conditions. Most notably, the gas prices for Years 7-20 are heavily (possibly too heavily) influenced by the forward gas price in the last year of NYMEX data used in the 2004 MPR forecast.[18]

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[17] On July 23, 2004, Energy Division circulated a "straw" MPR gas forecasting model to the MPR Workshop Participants and to the R.04-04-026 service list for review and comment. PG&E modified the gas forecast model on August 16, 2004 and circulated it to the R.04-04-026 service list. No changes to the PG&E gas model were proposed by the parties.

[18] In addition to the parties' pre-workshop and post-workshop comments, many documents on gas forecasting issues were prepared and reviewed by the parties, staff, and consultants. They include the 2004 MPR Cash Flow Model Escalation, 5/21/05; 2004 MPR Gas Forecast V1, 5/19/05; 2005 Cost of Carry Gas Forecast Model; and Cost of Carry Model Documentation, which were circulated to the service list on May 22, 2005. Circulated to the service list on June 24, 2005 were: CEC Gas Presentation, MPR Workshop, 6/20/05; and SCE Cost of Carry Presentation, MPR Workshop 050620. The final round of documents, circulated to the service list on July 6, 2005, consists of the Cost of Carry Gas Forecast Model-PG&E adjustment to Convenience Yield; PG&E, 2005

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1. Guiding Principles for MPR Gas Methodology

To help the parties focus on improving the 2004 gas model, staff prepared a set of general principles to guide development of the model, which was circulated to the parties with the ALJ Ruling of July 7, 2005. These principles were generally accepted by the parties, with the exception of SCE. A revised version of these guiding principles was developed in the Stipulation Regarding Guiding Principles and Short-Term Gas Price Forecast Methodology for the 2005 MPR Calculation (Gas Stipulation),[19] entered into September 7, 2005 by PG&E, California Cogeneration Council, CalWEA, Central California Power, SDG&E, and SCE.[20] The principles set forth in the Gas Stipulation are:

1. The natural gas prices used to calculate the MPR should reflect the behavior of market participants.

The MPR methodology is to consider the long-term costs of delivering fixed price electricity over a 10- to 20-year term. This methodology necessarily deals with hypothetical situations without exact parallels in the marketplace. Nevertheless, the methodology should, to the extent possible, reflect the behavior of market participants entering long-term fixed price contracts for the delivery of electricity.

2. Market data should be used to the extent possible.

Cost of Carry Gas Forecast Model-PG&E adjustment to Convenience Yield; and PG&E, MPR Gas Forward Price Proposal 2005-07-01-bis.

[19] The Gas Stipulation is attached as Appendix A.

[20] SCE endorsed only one of the principles, but participated in the rest of the Gas Stipulation, discussed in more detail below.

The methodology should either incorporate or at a minimum use this additional market data for benchmarking, if such data can be readily obtained and used, and is both reliable and available for review and publication.

3. For shorter-term contracts, forecast data should be verified against forward market data; for longer-term contracts that extend beyond available market data, forecasts should be benchmarked against fundamental costs and/or historical market data.

4. The methodology should be consistent with the evaluation of other products.

Energy companies use natural-gas price forecasts in a variety of areas, including procurement, risk management, financial valuation and resource planning. Absent clear and compelling reasons, the methodology adopted in this proceeding should seek to be consistent with forecast methodologies used by the state's utilities and regulatory bodies in other areas, as well as by other parties altogether.

5. The methodology should be consistent with previous regulatory decisions.

The Commission has adopted a methodology for evaluating conservation and energy efficiency programs in R.04-04-025. It is now conducting a proceeding to develop a consistent avoided costing methodology for a broader set of applications. Although the MPR inputs or methodology are not tied to results of the avoided cost proceeding, consistency across applications is a positive attribute of any proposed methodology.

We believe that these principles provide appropriate guidance in evaluating choices for the MPR methodology and adopt them. We note that they are guidance, not rules, and use them accordingly when evaluating proposed changes to the MPR gas forecasting methodology.

2. Gas Forecast for Years 1-6

The 2004 MPR 20-year gas forecast consists of two parts. The first, for the first six years of the proxy plant PPA, relies on information from NYMEX Henry Hub forward contracts. In their comments on the 2005 MPR, the parties generally agree that using NYMEX contracts for Years 1-6 is a sound approach. Some parties also entered into the Gas Stipulation, which proposes that most aspects of the 2004 gas price methodology for Years 1-6 of the proxy plant PPA should be continued. The Gas Stipulation proposes that we adopt the terminology "transaction costs," rather than "hedging costs," for certain costs related to NYMEX contracts. It also proposes changing the 2004 method for determining which NYMEX data to use, choosing to use a 22-day, rather than 60-day, averaging period and ending the period with the short-list date of the last utility to report its short list to staff. The Gas Stipulation reflects the views of a range of parties and received no major objections.[21] It is a reasonable resolution of the relatively small number of issues related to the first six years of the gas price methodology and is supported by the record. We will, therefore, adopt it.

3. Gas Forecast for Years 7-20

In contrast to the "fundamentals forecast" approach we adopted in 2004, SCE's cost of carry model is, in essence, based on methods used in markets for financial derivatives. This model takes the last year of available

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[21] Green Power supports the Gas Stipulation, but questions the language of the third guiding principle. We agree with PG&E and other stipulating parties that this variation from the originally proposed language is not a substantive problem.

NYMEX contract data and projects a price of gas into the future. The projection is created by using the "convenience yield" (the value to the owner of having gas in hand rather than having to go into the market to acquire gas), the interest rate, and data on Henry Hub forward contracts to project the last available contract price for the remaining years of the 20-year PPA term for the proxy plant.[22] PG&E endorses a modified version of the cost of carry model, substituting a "flat" adjustment rate for the convenience yield-based rate used by SCE. Other parties commenting on this issue prefer the 2004 method, though some have suggestions for minor improvements.[23]

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[22] SCE presents this process as follows:

> The cost of carry framework can be implemented by, first, estimating the forward net convenience yield on natural gas held for one year based on futures prices at the far end of the observable forward curve, then, using this long-term forward net convenience yield in conjunction with forward interest rates on one-year loans to estimate forward prices for delivery periods beyond the longest-dated futures contracts. This methodology can be expressed by a formula if we denote the forward interest rate on a one-year loan delivered at time *t* by r_t, the forward net convenience yield by $\bar{y}$, the delivery date of the longest dated Henry Hub futures contract by *T*, the longest dated Henry Hub futures price by F_T, and the estimated futures price for delivery one year after the delivery date of the longest-dated futures contract by $\hat{F}_{T+1}$:
>
> $$\hat{F}_{T+1} = F_T\left(\frac{1+r_T}{1+\bar{y}}\right)$$
>
> This procedure can be applied recursively to estimate forward prices for more distant delivery dates, each time using the correspond forward interest rate on one-year loans.

$$\hat{F}_{T+2} = \hat{F}_{T+1}\left(\frac{1+r_{T+1}}{1+\bar{y}}\right)$$

(SCE Post-Workshop Comments on 2005 Market Price Referent Issues, p. 23.)

[23] SDG&E, supported by PG&E, also proposes a modification to the transition between Years 1-6 and Years 7-20, which we discuss below.

PG&E and SCE base their approaches on their view that, in order to include "long term. . . fixed-price fuel costs" properly in the MPR, we must treat the gas fuel for the proxy plant as though it were provided through a 20-year fixed-price contract entered into when the proxy CCGT is built. PG&E expresses this position succinctly: "What would the price be for a long-term fuel supply contract entered into TODAY?" The PG&E answer involves constructing an admittedly hypothetical 20-year contract for gas, and then making an estimate of the cost of such a constructed contract. All parties, including PG&E and SCE, agree that such a contract is not commercially available and has no commercially available analogue.

It is also agreed that no market participant uses this approach in acquiring gas for CCGTs in California. There are no 20-year fixed price contracts for physical gas delivery. Rather, as Green Power points out, utilities and generators usually enter into tolling agreements, in which the purchasing utility supplies some or all of the cost of the gas fuel. Even SCE states that it does not use the cost of carry model for any of its own transactions. No other party uses the cost of carry model or advances the name of any other market participant who does. We conclude that we are more likely to produce an MPR connected with reality by adopting the practice of the marketplace than by developing a new model with no known application to the acquisition of gas fuel for CCGTs.[24]

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[24] The effects of the recent catastrophic hurricanes on the Gulf Coast demonstrate that no prediction of gas prices is going to be perfect—or even reasonably accurate—all the time. This reinforces our conclusion that relying on the behavior of market participants is more likely to produce an MPR gas forecast component that is a reasonable representation of costs over the longer term.

PG&E and SCE argue that, even if SCE's cost of carry model is not used in the marketplace, it is nevertheless required in order to comply with § 399.15(c), by developing a gas price model that fixes the cost of gas for the entire life of the proxy plant PPA. We believe that PG&E has created a problem that does not exist by reading the "fixed-price fuel costs" language of § 399.15(c)(2) without its context. In full, that section requires us to consider "[t]he long-term ownership, operating, and fixed-price fuel costs associated with fixed-price electricity from new generating facilities." As Green Power notes, the statute does not direct us *how* to undertake that consideration. Nothing in § 399.15(c) requires, or even suggests, that we must assume—contrary to industry practice—that gas fuel is acquired through very long-term contracts for physical delivery. No other element of the MPR is based on assumptions at variance with the behavior of market participants. Neither PG&E nor SCE has advanced any convincing argument showing that the long-term gas forecast should be the one exception.

SDG&E and PG&E[25] urge that we should adjust the relationship between the end of NYMEX data (no later than Year 6, and possibly Year 5, see D.04-06-015) and the beginning of reliance on the fundamentals forecasts in Year 7 to address the problems with the forecast in 2004. SDG&E suggests that, instead of using the escalation forecasting methodology of the 2004 MPR for Years 7-20, we should use a three-year straight line blending between the near-term (Years 1-6) and the long-term (Years 7-20), and then use the average of the

[25] PG&E supports this position if we do not adopt PG&E's modified cost of carry method.

fundamental forecasts for the remaining years.[26] This method retains the absolute value of the fundamentals-based gas price forecasts and eliminates the escalation process for Years 7-20 that we used in 2004, which was the subject of criticism from the parties. We agree that this method will eliminate, or greatly reduce, the problems with the forecast generated using the 2004 model, and we will adopt it.

Our conclusions on the gas forecast issues are consistent with our guiding principles. Market participants use some mixture of market data (NYMEX prices) and fundamentals forecasts for estimating long-term gas prices in a variety of settings, not only new PPAs for electricity produced from CCGTs. We have used a similar approach in D.05-04-024, issued in the avoided cost proceeding (R.04-04-025). This approach combines transparency with reality testing against both current marketplace behavior and historical data, providing assurance that the 2005 gas forecasting model is a reasonable way to construct the MPR. It is also consistent with, though not identical to, the methods adopted in R.04-04-025.[27]

D. Time of Delivery Profiles

In 2004, some parties recommended a change to the Commission's methodology, to consider a "time of delivery profile" to more accurately reflect the value of electricity provided to the utility over the different hours of the year. In D.04-07-029, we recognized that the TOD method had several advantages by

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[26] In 2004, three public forecasts and one private forecast were averaged.

[27] The gas forecasting methodology adopted in D.05-04-024 uses one public fundamental forecast, while the MPR methodology uses an average of several forecasts, both public and private.

virtue of its precision and transparency. A number of parties endorsed some variant of this approach and encouraged the Commission to begin examining it for implementation for the 2005 RPS solicitation. Suggested benefits include a more accurate estimation of the value of capacity, avoidance of problems associated with applying MPRs to products that are neither strictly baseload nor peaking, and better fit with at least one of the utilities' proposed method of evaluating RPS bids.[28]

Parties have provided substantial information and analysis on TOD issues for the 2005 MPR.[29] Parties, except Solargenix, endorse the use of TOD profiles, though they propose a variety of specific methods of implementing the concept.[30]

Forward looking market data. PG&E & SDG&E favor this approach. PG&E's TOD factors are based on market forward energy price information

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[28] In D.04-07-029, we also identified other issues for further exploration, including understanding how the TOD profile would be constructed, how public they would be, and whether separate TOD profiles for each utility would be appropriate.

[29] A number of documents were circulated to the service list. On June 24, 2005: TOD MPR Workshop #2, Agenda Final 6/24/05. On July 6, 2005: 2005 MPR TOD workshop sign-in sheet (June 27); E3 Presentation, TOD Profile Benchmarking, 6/27/05; E3 Presentation, TOD Profile Comparison, 6/27/05; Green Power Presentation, TOD Proposal 6/27/05; Green Power Proposal on TOD Profiling; Green Power TOD Proposal, EAP calculator; PG&E, MPR TOD Proposal 2005-07-01; SCE TOD Answers; and SDG&E Time of Delivery Workshop. On July 11, 2005: 2005 MPR workshop minutes. On July 14, 2005: Corrected TOD comparison spreadsheet (filename: 47717 Ver. 2).

[30] See July 7, 2005 MPR briefing Ruling (Appendix B) for a detailed description of the various TOD proposals. Solargenix sets out its position in its post-workshop comments, arguing that the 2004 MPR's use of proxy baseload and peaker plants should be continued, with some modifications.

gathered from broker quotes and exchange prices for energy forwards. The forward prices are then used to develop prices for subperiod blocks of power and create PG&E proprietary hourly price streams by scaling an hourly price shape for each month to the monthly forward price. The proprietary hourly price shapes are created by calibrating exponential functions of hourly load to prices.

SDG&E's TOD factors are based on a combination of historical California Power Exchange (PX) day ahead market prices and forward price information. The hourly prices are altered so that the adjusted hourly prices averaged over the quarter equals the observed forward market on-peak and off-peak prices.[31]

Qualifying Facility (QF) pricing. SCE proposes using all-in TOD factors derived from existing allocation factors used for SCE's existing QF contracts. The year would be broken into six TOD periods and a factor developed for each of those TOD periods.

Hourly profiles. Green Power proposes a new methodology for constructing TOD profiles, based on hourly profiles. The methodology would be the same for all utilities, but the set of 576 "adders" that constitutes the TOD profiles would be utility-specific.

PG&E and SDG&E argue persuasively that the utility is in the best position to synthesize the market information used to reflect the relative value of electricity to the utility at various time periods. They also note that it is

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[31] A 60-day average of 2007 on-peak (6 x 16 contracts) and off-peak forward prices from wholesale brokers Tullett-Liberty (information at www.tullett.co.uk/global/global/home/) was used as the benchmark forward prices.

important to rely on current market information, as opposed to historic information, because historic TOD factors can easily become outdated and inaccurate as benchmarks of relative value.

Several parties, including SCE, point out that SCE's QF TOD factors were developed in the mid-1990's for the purpose of developing QF payments. The purpose, method, and timeframe of SCE's QF TODs differ from those of PG&E and SDG&E. As noted above, it is important to rely on current market information, as opposed to historic information. Therefore, SCE's QF-derived TODs are not appropriate for the MPR. SCE should recalculate its TOD profiles using market forward energy price information in a fashion similar to that of PG&E and SDG&E.[32] SCE should make this change for its 2006 solicitation. Delaying the change will, however, result in the use of different TOD methods among the utilities for the 2005 solicitation. Although this inconsistency is troubling, it is less problematic than the potential for delay and confusion that would be introduced if SCE were to revise its 2005 TODs for its now-closed 2005 solicitation.

We agree with PG&E and SDG&E that the utilities' TOD profiles should be the basis for the MPR's TODs. The utilities are the relevant market participants in setting the value to them of electricity during various time periods. Green Power, which has consistently advocated the use of TODs, has proposed a different methodology. We decline to adopt Green Power's proposed methodology, which is not used by any utility. We recognize, as Green Power proposes, that we could require the utilities to adopt Green Power's TOD

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[32] SCE's suggestion that any revision to its TOD factors for purposes of the MPR be applied to existing QF contracts is more properly addressed in R.04-04-025.

method, but we see no reason to do so. The theoretical value of a uniform method for the utilities, which Green Power advances, is approximated in practice by our use of utility TODs that have been developed using essentially similar methods[33] among the three utilities. These methods produce TODs with six or nine periods, in contrast to Green Power's 576 adders. Green Power has not documented quantitative benefits of its method that are commensurate with the radically greater granularity of its proposal.[34]

Thus, to derive the maximum benefit from the use of TOD factors, we will adopt IOU-specific TOD profiles developed by each of the utilities.[35] This approach ensures that both the utility and the generator receive the full value of the product bid in the solicitation; the TOD profiles provide a reasonable estimate of the value of energy and capacity provided by the resource; and that the TODs provide adequate accuracy without too much complexity. This method also has the advantage of being readily repeatable in future years.

PG&E, SDG&E, and Green Power recommend that the utilities' TOD factors be approved by the Commission during the review of the utilities annual RPS procurement plans and proposed RFOs. SDG&E also notes that the utilities' procurement review groups and Commission staff would have the opportunity to review the utilities' application of the TOD periods and factors and the

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[33] Once SCE revises its TODs.

[34] We acknowledge and appreciate the efforts of Green Power in developing and presenting its proposals.

[35] SCE's revised TODs will be included for 2006. Its QF-based TODs are included for 2005 only.

reasonableness of the production profile of the generator during the evaluation and contract approval process.

We agree that the TOD factors should be approved by the Commission during the review of the utilities' short-term RPS plans and proposed RFOs. In order to do this, however, a methodology for evaluating reasonableness of the utilities' TOD profiles is required. Parties provided no specific proposals on this topic. Consequently, we will require the parties to present TOD evaluation and benchmarking proposals for the 2006 RPS procurement process, on a schedule to be set by the Assigned Commissioner and assigned ALJ.

The majority of the parties commented that if the baseload MPRs are time-differentiated, a consistent process of time-differentiation should also apply to:

- the bid prices that potential RPS projects will submit;
- the least-cost, best-fit evaluation process used to select those winners; and
- the payment of SEPs.

We agree that time-differentiated MPRs should be coordinated with the time-differentiation of all other aspects of the RPS process – bidding, LCBF evaluation, and SEP payments. Without this coordination there is the potential for confusion among bidders, the gaming of bids, and the excessive use of PGC funds. Consequently, when the utilities file their RPS contracts with the Commission for approval, they will need to demonstrate consistent application of TODs throughout the procurement process.

To this end, SCE recommends that TOD factors adopted for a particular solicitation cycle be "hardwired" into any and all contracts signed during that cycle. We adopt this recommendation. PG&E notes that it "refreshes" the valuation of its TODs, because it employs a market-based approach to its internal valuation of resource options that incorporates the most current market information available. PG&E's practice of updating its valuation is consistent with our use of TODs in the MPR as long as the TOD profiles themselves remain fixed from publication in the RFO through the entire RPS solicitation cycle.

SCE and SDG&E note that the TOD adjustment to represent the value of the acquired power can be either multiplicative (*e.g.*, a factor of 1.5) or additive (*e.g.*, addition of $.01/kWh). They urge us to choose one method. SDG&E suggests that the only requirement should be that TOD factors should average either 1.0 on a multiplicative basis or 0.0 on an additive basis. This will ensure that projects evaluated with TOD factors are comparable to those projects without TOD factors. Since the TOD methods of all three utilities in effect support the use of multiplicative TOD factors, we adopt the use of multiplicative TOD factors.

E. Non-Gas Methodology and Inputs

We continue to use the SCE cash flow model we adopted in D.04-06-015, with the same non-gas input categories: capital costs, capacity factor, heat rate, fixed operations and maintenance (O&M), variable O&M, insurance, property tax, and transformer losses/generation meter multiplier. We reiterate, as we noted in D.04-06-015, this is a decision about methodology. Specific inputs will be calculated and disclosed in the materials accompanying the draft resolution for the 2005 MPR.

1. Methodology for Selecting Non-Gas Inputs

Section 399.15(c)(2) calls for the proxy to be based upon new generating facilities. The use of the plural "facilities" indicates that more than one facility is to be used for the proxy plant. Accordingly, D.03-06-071 adopted the use of representative statewide numbers for factors such as heat rate and line losses. D.04-06-015 further clarified that a consistent set of input assumptions are to be used to calculate the MPR, taking into account certain cost tradeoffs (*i.e.*, inputs based on internally consistent assumptions).

a) Lowest Quartile or Midpoint of Reasonable Range of Inputs

TURN and the CalWEA group urge the Commission to adopt a baseload MPR that reflects a middle-of-the-road approach to the selection of the key cost parameters for a CCGT plant recently built or under construction.

SCE argues that an assumption implicit in § 399.15(c) is that the prices obtained under § 399.15 (c)(1), *i.e.*, prices obtained by considering the long-term market price of electricity for fixed price contracts, would be very similar to the prices obtained under § 399.15(c)(2), *i.e.*, prices obtained by considering the long-term ownership, operating, and fixed-price fuel costs associated with fixed-price electricity from new generating facilities.
Thus, SCE argues, the "middle-of-the-road" and "midpoint" approaches advocated by CalWEA and TURN both ignore the role of competition as a legitimate source of downward pressure on the MPR. SCE asserts that, in a real utility procurement solicitation, factors such as the ability of the developer to build the project at the bid price and the value of the project to ratepayers would weight the outcome toward the most cost-competitive projects that would be likely to be successful. SCE therefore urges us to pick values in the lowest quartile of the range of reasonable input values, to reflect the impact of competition on PPAs.

As we have previously determined, however, there currently is no robust competitive market for long-term PPAs for CCGTs. SCE's proposal therefore does not reflect the current statewide situation, as D.03-06-071 requires. We therefore will adopt the "mid-point approach."

b) Use of Market Surveys, Competitive Bids, and Secondary Market Data

Market surveys and competitive bids could provide useful information about the capital costs of new construction. However, since there are no long-term (*e.g.*, 20-year) competitively bid projects in the market; the next best alternative is to do a market survey of capital. Even if long-term competitive bids did exist, several issues would need to be addressed before that information could be used to derive MPR inputs. The greatest obstacle, as PG&E points out, is the confidential nature of the costs underlying a competitive bid, which will make it difficult to isolate the capital cost component of a proposed generating unit to be constructed as a result of competitive solicitation. We could revisit the use of competitive bids when they exist in sufficient numbers to be useful and the issue of confidentiality has been addressed.[36]

With respect to market surveys, TURN, CalWEA, and PG&E recommend using values that reflect the cost of a range of CCGT projects that have been built in the last few years or are currently under construction in California. TURN further argues that we should not use the current market survey data obtained from the Energy Commission's application for certification (AFC) process, but should only use actual data from operating projects after initial commercial operations, or from those under construction, and subject to independent audit.

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[36] We reject ORA's proposal that we use utility executed contracts because these issues cannot be resolved in the context of the 2005 MPR.

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We adopt PG&E, TURN, and CalWEA's recommendation that the market survey of plants most recently constructed or currently under construction should be used when identifying specific input values. The Commission will also refer to the cost of CCGT facilities it has reviewed in the last few years.[37]

Lastly, PG&E, TURN, and the CalWEA group caution against the use of data from "secondary market" sales of distressed, bankrupt, and/or partially completed projects. PG&E points out that we found in D.03-12-059 that Mountainview's purchase price reflects capital costs significantly below that of any comparable new facility, and has limited relevance for the establishment of an MPR. SCE, however, endorses the use of secondary market data, primarily because plants purchased in the secondary market do participate in the PPA market and are "new" until they are operational.

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

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[37] The Energy Commission's cost of generation report is produced roughly biannually. The August 2003 Comparative Cost of California Central Station Electricity Generation Technologies report, www.energy.ca.gov/reports/2003-08-08_100-03-001.PDF, is the most recent. This report was prepared in support of the Energy Commission's 2003 Integrated Energy Policy Report (IEPR) Subsidiary Volume: Electricity and Natural Gas Assessment Report (www.energy.ca.gov/2003_energypolicy/index.html).

The Energy Commission does not plan to adopt its new cost of generation report in time for the 2005 MPR calculation. Analysis relevant to the 2005 MPR may, however, be available at a staff level. We direct staff to confer with Energy Commission staff to determine what information and analysis related to the cost of generation may be available for use in the 2005 MPR.

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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.

c) Applicability of Out-of-State Data

The CalWEA group argues that the Commission should rely only on capital cost data from CCGT projects built or under construction in California. Although California undoubtedly imports small amounts of power from new CCGTs sited outside the state, the great majority of CCGT generation consumed in the state is also produced here. CCGT projects that are not in California will not be sufficiently representative of the cost of building and operating such plants in the California market. Furthermore, for plants outside of California to be reasonably comparable, transmission costs to deliver the plant's output to the California marketplace – including possible congestion costs to reflect the higher prices in the California market – would have to be included. This could greatly complicate the MPR determination, as such transmission and congestion costs could be highly location-specific and very speculative over the long term.[38] SCE, on the other hand, believes that to the extent that a plant is located in an area from which power could be delivered in to the California market, the costs associated with that plant are legitimately part of the cost database, provided that delivery penalties are also included.

We agree with the CalWEA group that the use of out-of-state data would require the demonstration that long-term firm electric transmission capacity is available, at a known cost, to move the power from the specific location of each out-of-state plant to California. No party has shown that such a demonstration can be made using reliable data. Therefore, we reject SCE's proposal and limit our consideration of capital costs for developing the MPR to those plants located in California.[39]

2. Operational Characteristics of Proxy Plant

D.03-06-071 adopted a proxy plant methodology for calculating the MPR, using a combined cycle proxy plant for the baseload product and a combustion turbine proxy plant for the peaking product. The decision also determined that the "market price referent will be calculated as an all-in cost,

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[38] In addition, SDG&E points out that significant costs attributable to land acquisition, permitting and development, pollution/emission control equipment, and other permit requirements (noise abatement, aesthetics, water supply cost, environmental mitigation, etc.) make cost information from outside California unreliable relative to the California market.

[39] With respect to certain operational issues, for example the characteristics of the proxy plant's turbine or its heat rate, staff may consult sources of information that include data not from California. Any such data used by staff to calculate the 2005 MPR must be presented in the materials supporting the draft resolution containing the 2005 MPR calculation.

with an exception for as-available capacity." (*Mimeo.*, at p. 74.) Section 399.15(c)(2) also calls for the proxy to be based upon new generating facilities. Accordingly, D.03-06-071 elected to use representative statewide numbers for factors such as heat rate and line losses with location-specific costs used only when those costs have already been specifically quantified for a particular geographic region, such as the cost of emissions offsets. D.04-06-015 also clarified that the MPR does not represent the cost, capacity or output profile of a specific type of renewable generation technology.

a) Adjusting MPR to Reflect Renewable Attributes

PG&E, SCE, and SDG&E argue that even though the CCGT is the baseload proxy for establishing the MPR, its operating characteristics are different from those of the various renewable resources. By not adjusting the operational characteristics of the MPR proxy plant to reflect the generating attributes (integration costs, dispatchability, resource adequacy, etc.) of renewable resources, the IOUs argue, renewable bids will be overvalued relative to the MPR CCGT. Green Power opposes modifying the CCGT to reflect the operating characteristics of different renewable resources. Green Power argues that modifying the assumed capacity factor used for the proxies in order to model the expected operating behavior of renewables distorts the resulting calculated cost of electricity from the proxies themselves.

We agree with Green Power. The proxy plant, as we have repeatedly noted, does *not* represent a specific type of renewable generation technology; rather the MPR is to represent the presumptive cost of electricity from a *non-renewable* energy source. The operating characteristics of renewable energy sources are more properly addressed in the context of the least cost/best fit evaluation of bids, not the MPR.[40]

b) Calculation of a CT Proxy

Parties, staff, and consultants thoroughly explored improvements to the peaking plant proxy for 2005. PG&E and several other parties nevertheless recommend that an MPR based on a peaking proxy unit not be adopted for use in 2005. Rather, the MPR for peak period energy should be established by applying factors derived through the TOD methodology to the baseload MPR. The application of TOD factors to the baseload MPR would eliminate the combustion turbine (CT) - based peaking MPR and the "blended" off-peak MPR (adopted in D.04-07-029). Solargenix is alone in arguing that the 2005 MPR should not use TOD factors, because in Solargenix's view, both § 399.15(c) and D.03-06-071 specifically require the use of a proxy peaker plant.

PG&E responds that its proposal does not conflict with the statutory direction to establish a methodology to determine the MPR in consideration of "the value of different products including baseload, peaking, and as-available output."[41] TOD factors are based on the forward value of electricity during different TOD periods. Output from baseload, peaking, and as-available units may be time-differentiated by these periods, so the application of TOD factors to the MPR will result in a market price for each product and electric generating unit. Thus, it is not necessary to separately adopt an MPR

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[40] To the extent that there are serious unresolved issues related to the operating characteristics of the renewable resources in the bid evaluation process, we may revisit the criteria to be used in the least cost/best fit process in 2006.

[41] Section 399.15(c)(3).

based on the cost of an electric generating unit operated only during periods of peak demand.

We agree with PG&E. The application of TOD factors to the baseload MPR does take into account "the value of different products including baseload, peaking, and as-available output." Nothing in the statute requires us to use multiple plant proxies in order to do so.[42] Thus, we will no longer calculate a CT-specific MPR based on the cost of an electric generating unit operated only during periods of peak demand.

c) CCGT Turbine

SCE urges that we adopt the most advanced, state of the art turbine as the proxy turbine, which SCE proposes as the Siemens-Westinghouse 501 G. As PG&E points out, this turbine is not commercially employed in California. Thus, SCE's proposal is inconsistent with our basic conclusion in D.03-06-071 that statewide average values should be used for the proxy plant. Rather, we should use the most advanced commercially available turbine that is used by new plants in California. We are persuaded by PG&E that the General Electric (GE) "F" Series turbine is the turbine that meets this requirement for the proxy plant at this time. We instruct staff to use this equipment for the proxy plant, obtaining information from GE and from a survey of new power plants in California for benchmarking purposes.[43]

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[42] Indeed, the 2004 "blended" MPR is not based on a specific proxy plant.

[43] We recognize that at some point in the future, a different machine (perhaps the Siemens G proposed by SCE) may become the equipment that best matches our "statewide average" standard. Parties are free to bring to the attention of staff any such adjustment to the particular equipment for consideration for the proxy plant, but we do not anticipate changing the standard of appropriateness we enunciate in the text.

d) Capacity Factor

A critical issue raised by the parties is whether the MPR should continue to use the capacity factor of 92% adopted in 2004. This capacity factor assumes that the proxy plant is running essentially all the time, and captures the effects of both maintenance and unplanned outages. SCE and PG&E, supported by SDG&E, argue that this assumption continues to be appropriate for a proxy plant possessing a hypothetical fixed-price, must-take contract.

PG&E acknowledges that the capacity factor of a typical CCGT will be lower. However, the operational characteristics (dispatchability and resource adequacy) of the benchmark MPR proxy are different from those of the renewable facilities, resulting in a difference between operational value and price. On the other hand, imputing reduced operating periods to the MPR proxy would result in a higher per-kWh MPR under the cost-recovery methodology used to calculate an "all-in" MPR, a situation that would improperly exacerbate the difference between operational value and price. Consequently, PG&E does not recommend changing the capacity factor of the baseload MPR.

The CalWEA group disagrees with the IOUs, stating that the movement to a time-differentiated MPR will lead to a downward adjustment of the capacity factor in response to the pricing signals conveyed by the TOD profiles. The CalWEA group argues that the TOD factors that the IOUs have proposed will lead to a TOD MPR price below the operating costs of the proxy CCGT plant in super off-peak and many off-peak hours.[44] In essence, the

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[44] Using the 2004 variable operating costs ($47 per MWh), the CalWEA group notes that these costs are about 78% of the total 2004 MPR price ($60 per MWh). In this example,

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CalWEA group notes, the use of TOD MPR prices introduces the reality that CCGT plants in California are dispatched based on market signals, and the choice of capacity factor must reflect this reality as well. The CalWEA group estimates that in at least 20% of hours it is simply not economic to operate a CCGT in the California market, and the owner of a CCGT cannot recover fixed costs if the plant is not operating. CalWEA group therefore urges us to use a capacity factor in the range of 80%, not 92%.

We agree with the IOUs that a developer with a fixed-price must-run contract, *paid a levelized price*, would find it economic to run in all hours, operate at full load in all hours, and can recover its fixed costs at a price that assumes the maximum feasible amount of generation. That is, the developer is indifferent to when it generates because it is getting paid the same $/kWh in every hour. This approach was appropriate for 2004 because we were assuming the generators were being paid a levelized all-in bid price, *i.e.*, would generate in all hours-less maintenance and forced outages (92% capacity factor).

However, as the CalWEA group points out, the introduction of TODs provides generators with a market pricing signal. The generator is now paid a different $/kWh/TOD period depending on when it generates. Consequently, the generator will adjust its generation profile (capacity factor) to maximize profitability, because the TOD MPR price will be below the operating costs of the proxy CCGT plant in super off-peak and many off-peak hours. The end result is that the generator will not operate in hours where its marginal costs

for those hours that have a TOD factor less than 78%, an MPR based on TODs will not cover the variable operating costs of the proxy plant.

are greater than its marginal profits, which will be something below 92% of the time.

PG&E's comments about keeping the capacity factor at 92% until the dispatchability and resource adequacy characteristics of generating units employing the various renewable technologies have been addressed and compared with those characteristics of the CCGT proxy are misplaced. As previously noted, the MPR does not represent the cost, capacity or output profile of a specific type of renewable generation technology. Rather, as § 399.15(c) states, the MPR is to represent the presumptive cost of electricity from a non-renewable energy source.

We now turn to the derivation of the 2005 MPR capacity factor. The CalWEA group has identified the key element in resolving the capacity factor dispute: the utilities' TOD profiles. As noted above, the TOD profiles are market price signals to which the proxy plant generator will be responding. Consequently, we are not confined to making a relatively less informed choice between either a full-time, full-load 92% capacity factor, and some other capacity factor derived from operation of a relatively small number of plants. We will instead use the utilities' TOD profiles to calculate a statewide average capacity factor.[45]

Beginning with 2005, on an annual basis staff will calculate the capacity factor for the MPR CCGT by computing a capacity factor based on

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[45] We direct staff, in developing the capacity factor, to choose the lower of (1) the technical operating limit as set by the 2005 MPR inputs, or (2) the capacity determined by the economic operating hours based on the TOD profiles and the costs of shut-down and start-up.

each utility's TOD profile and then averaging the three MPR capacity factors to arrive at a statewide average capacity factor to be used in the final MPR calculation. This average capacity factor would be calculated every year based on the revised TODs filed by the utilities with their draft RFOs each year. This approach embraces the "market behavior" approach because we would be modeling what the owner of a new CCGT would do if it contracted with a California IOU. While none of the parties recommended this specific approach, we believe that it is a logical extension of the CalWEA group's observation that TODs send pricing signals to the generators.

Using TODs in this way provides two additional benefits. It increases the consistency of the data used for calculating the MPR by relying on the same information submitted by the utilities for related functions, rather than searching for external data and deciding how to weigh it. It also allows us to establish a method for calculating a capacity factor for the MPR (use TOD profiles) that can easily be updated annually, if needed (use currently submitted TOD profiles for that year).

e) Heat Rate

With a new turbine comes a "new and clean" heat rate set by the manufacturer. Parties have differing views on whether the "new and clean" heat rate should be used for the proxy plant[46] (as we did in 2004), or whether an adjusted heat rate based on actual operation of the turbine over time should be used.[47] Parties have identified three possible adjustments to the heat rate

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[46] SCE and ORA support this position.

[47] The CalWEA group, ORA, and TURN urge this approach.

calculation as adopted in 2004. One is an adjustment for the use of dry cooling, which the CalWEA group points out was identified in D.04-06-015 but not applied to the 2004 MPR. The CalWEA group, based on the record in the Energy Commission certification process for the Otay Mesa and Sutter power plants, suggests that the adjustment should be an increase in the heat rate in the range of 200 Btu. SCE asserts that, since the dry cooling adjustment is to some extent dependent on ambient temperature, a plant-specific inquiry is required.

We agree that we should make this adjustment this year. We decline to adopt SCE's approach, which is inconsistent with the statewide average value approach to the proxy plant. The record is currently insufficient to support a particular numerical value for a dry cooling adjustment. We instruct staff to gather information from the manufacturer about the GE "F" series turbine, as well as information about the operation of new California power plants, to provide the basis for the dry cooling adjustment for the 2005 MPR. The sources of information should be explained in the supporting materials for the draft 2005 MPR resolution.

The CalWEA group supports the use of a "degradation factor" of 3.5%, used in 2004 to reflect degradation in performance over the life of the turbine. SCE believes that this figure is too high. We do not have a sufficient record to resolve this technical issue. We therefore adopt SCE's suggestion that staff obtain from the manufacturer of the proxy turbine (GE) the degradation factors it recommends, and add that staff should also make inquiries to any other sources that may yield useful information and apply the results in the 2005 MPR calculation. The sources of information should be explained in the supporting materials for the draft 2005 MPR resolution.

Finally, the CalWEA group observes that using a capacity factor lower than 92% will have an impact on the achieved heat rate, because the proxy plant will have less efficient operation when starting and stopping more frequently. Other parties agree that lower capacity factor could affect heat rate (though SCE and PG&E do not agree that we should apply a lower capacity factor). Because we do not have quantitative information about the effect of lower capacity factor on heat rate, we instruct staff to collect information about the impact of a lower capacity factor on heat rate, and include such information, if relevant, in the staff calculation and supporting materials for the 2005 MPR draft resolution.

f) Size of Proxy Plant

The CALWEA group argues that the Commission needs to consider the economies of scale that may be included in data on the largest CCGT plants. Data collected by the Energy Commission indicate that the average size of all the plants over 300 MW that have come on-line since June 2001 is 616 MW. The average size of all plants expected to come on-line after June 2001 is 300 MW. Thus, the costs of a 500 MW plant, such as Palomar, are more likely to reflect the typical new plant built in the California market and should be considered in calculating the baseload MPR benchmark. We will take the CALWEA group's comments in the form of guidance, and reiterate that a consistent set of input assumptions are to be used to calculate the MPR, taking into account certain cost tradeoffs (*i.e.*, inputs based on internally consistent assumptions).

3. Cost of Capital for Proxy Plant

Before it can operate, the proxy plant must be financed and constructed. Most parties,[48] with the exception of SCE, are critical of the financing assumptions used in the 2004 MPR. They assert that those assumptions are internally inconsistent, having combined a merchant plant capital structure (70% debt/30% equity) with typical utility rates of interest on debt and return on equity. To address this concern in 2005, we asked the parties to comment on three related aspects of the capital structure and cost of the proxy plant: financing of the proxy plant (project-based or total balance sheet); cost of capital for a proxy plant having a long-term PPA with a creditworthy IOU (same as IOU or different); and development of a specific weighted average cost of capital for a proxy plant having a long-term PPA with a creditworthy IOU.[49]

Most parties, again with the exception of SCE, agree that the proxy plant should be financed not as a stand-alone project, but on a total balance sheet basis. PG&E and TURN argue that most developers either are large corporate entities, or have more than one generation project; few if any have only one CCGT with one long-term PPA (the one being used as the proxy plant) in their portfolios. SCE counters that an independent power producer has access to project-based financing, but offers no evidence that new CCGT projects in California are actually financed on a project basis. We agree with the majority

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48 The CalWEA group, Green Power, PG&E, Solargenix, and TURN.

49 Documents circulated to the service list on July 11, 2005 include: 2005 MPR workshop minutes, distrib. Parties, 7/11/05; PG&E email (July 5, 2005), "Summary of MPR Cost of Capital Financing Assumptions Meeting" with 2 attachments—070505 E3 Presentation, MPR Cost of Capital and 070505 PG&E Cost of Capital Presentation.

of commenters that the MPR proxy plant should be assumed to have access to financing based on the balance sheet of the developer. We therefore adopt PG&E's suggestion that the debt/equity profile of the proxy plant should reflect a more conservative financing structure of 50%/50% rather than the 2004 MPR assumptions of 70%/30%.[50]

The parties diverge, however, on the question of the cost of capital. The inconsistent 2004 assumptions could be remedied either by adjusting the 2004 debt/equity allocation to be more like that of the utilities, or by adjusting the interest rate/return on equity allocation to be more like that of a merchant plant. Analysis of the allocation of the risks of developing and operating the proxy plant is key to the parties' positions.

PG&E and SDG&E urge that we adjust toward the utilities' cost of capital. They argue that a long-term PPA with a credit-worthy utility allows the generator to transfer almost all market and regulatory risk to the utility purchasing the power. The generator's risk therefore closely approximates that of the utility. TURN, Green Power, Solargenix, and the CalWEA group, on the other hand, argue that an independent generator retains substantial risks, even with a long-term PPA with a creditworthy utility. These risks include construction cost overruns, operational performance problems, and ongoing capital and O&M costs that are higher than those contemplated by the PPA. TURN also notes that a utility faced with similar problems could incorporate a

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[50] While a developer could use the 20-year PPA and the strength of its balance sheet to increase the leverage in financing a particular project, the consensus of the parties is that the developer would use those characteristics to reduce the proportion of debt in project financing.

request for funds to cover them in its next general rate case, while an independent generation developer has no comparable opportunity to ask for more money to cover forecasts that are shown to be inadequate. Thus, the utilities' financial risks are noticeably lower than those of an independent generator.

We agree with TURN that the utilities' risk profile does not fit the independent generation developer of the MPR proxy plant. Although the long-term PPA transfers significant risks to the purchasing utility, the developer retains risks related to construction and some risks related to operation. Further, as the CalWEA group notes, the generator under contract is paid only for power the plant produces, unlike rate-based utility-owned generation. Thus, the risk profile of the proxy plant should fall somewhere between that of a merchant generator (selling into the market without a long-term contract) and a utility.

These assumptions are operationalized in the development of a weighted average cost of capital (WACC) for the proxy plant. Having concluded that a capital structure similar to that of a utility is appropriate, but a risk profile the same as that of a utility is not, we must choose a way to determine the WACC that is consistent with each of those conclusions.

The record contains a relatively detailed examination of options for implementing a WACC for the proxy plant. As part of the intensive workshop process, a working group of parties and staff, assisted by consultants from E3, met to consider the costs of financing.[51] Three possibilities were considered: a cost of capital the same as that of utilities ("Option 1"); a cost of

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[51] The parties participating in the working group were: CalWEA group, Cogeneration Association of California, Green Power, ORA, PG&E, SCE, and Solargenix.

capital the same as that of current merchant plant generators in California (*e.g.*, AES, Calpine, Reliant) ("Option 3"); and a cost of capital of industrial companies in the Standard and Poor's 500 index (S&P 500) with risk profiles that are comparable to that of the independent power generation industry as a whole ("Option 2").

All parties in the working group agree that Option 3—using current California merchant generators—is not appropriate for the MPR proxy plant. These generation developers currently have portfolios with significant merchant generation capacity, with no long-term PPAs to guarantee payment streams for the energy from those facilities. Moreover, the financial difficulties of some merchant generators are driving their cost of capital far above what would be considered a statewide average cost. These factors combine to render the cost of capital under Option 3 inappropriately high.

The remaining choices—Option 1 (a utility cost of capital) and Option 2 (S&P 500 comparison group)—share some characteristics. They are internally consistent and use publicly available, transparent data. PG&E prefers Option 1. ORA, TURN, Green Power, and the CalWEA group urge us to adopt Option 2. SCE maintains that the assumptions of the 2004 MPR should be continued. We agree that the Option 2 approach is most consistent with our analysis that the proxy plant with a long-term PPA transfers much but not all of its risk to the purchasing utility. Illustrative results for the 2005 MPR are shown below:[52]

Option 2 – Illustrative 2005 MPR WACC

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[52] Staff will calculate the actual WACC for the 2005 MPR in the draft resolution.

	DE Ratio	Cost	After-Tax
Debt	50.0%	6.58%	2.01%
Common Stock	50.0%	12.30%	6.15%
	100.0%	-	8.16%

As the CalWEA group notes, Option 2 produces a WACC that is only about 0.6% different from that obtained by using a utility WACC. We are thus reasonably confident that Option 2 captures meaningful differences between the risk profiles of the proxy plant and California's large utilities, without exaggerating those differences.

TURN asks that we clarify the benchmarks used for the high and low ends of the S&P 500 grouping and that the numbers be updated in future years. We direct staff to make the appropriate clarification and to seek information that can be used for an annual update of the WACC for the proxy plant using the approach outlined by E3 in the "070505 E3 Presentation, MPR Cost of Capital" circulated to the parties on July 11, 2005.

F. Modifications to 2004 MPR Model

1. Nominal MPRs Reflecting Different Project On-line Dates

The July 7, 2005 MPR Briefing Ruling asked several questions regarding how to operationalize the MPR, *i.e.*, use the MPR to evaluate RPS bids, including:

- Does the MPR need to be in the same nominal dollars as the all-in bid price?

- Does the Commission need to calculate a series of MPRs corresponding to different project on-line

> dates? If so, how should non-gas inputs, such as capital costs, be adjusted?

CalWEA group, SCE, PG&E, and SDG&E agree that the MPR should be calculated in nominal dollars[53] for at least two reasons. The bid prices of projects are expressed in nominal dollars. In addition, since the utility is guaranteed recovery of renewable power purchase costs at or below the MPR, there should be no ambiguity regarding the comparison of bid prices with the MPR.[54] The parties[55] also agree it is beneficial for the Commission to calculate a series of MPRs for different project on-line dates. Since bidders express their final contract prices in nominal dollars, and projects may require several years' lead time before deliveries begin, the Commission should calculate a series of MPRs corresponding to different project on-line dates in 2006 through 2010. (See Resolution E-3942.)

While all parties other than Solargenix agree that the Commission should calculate a series of MPRs for different project on-line dates, there is disagreement on how to do that calculation. PG&E recommends that the

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53 Nominal dollars are economic units measured in terms of purchasing power of the date in question. A nominal value reflects the effects of general price inflation. Real or constant dollar values, by contrast, are economic units measured in terms of constant purchasing power. A real value is not affected by general price inflation. Real values can be estimated by deflating nominal values with a general price index, such as the implicit deflator for Gross Domestic Product or the Consumer Price Index. (www.nps.navy.mil/drmi/definition.htm.)

54 "Procurement and administrative costs associated with long-term contracts entered into by an electrical corporation for eligible renewable energy resources pursuant to this article, at or below the market price determined by the commission pursuant to subdivision (c) of Section 399.15, shall be deemed reasonable per se, and shall be recoverable in rates." (Section 399.14(f).)

Commission adopt an MPR for each of the five years following 2005 to accommodate different on-line dates of projects benchmarked against the 2005 MPR. This would be accomplished by escalating the 2005 MPR through 2010 by the rate of inflation. After the five-year period (after 2010), it should be assumed that technology improvements offset the escalation of capital costs, so no further adjustment due to inflation would be necessary.

SCE argues that if the Commission assumes that there will be no significant improvements in heat rate efficiencies until after 2010 in calculating the 2005 MPR, then the Commission must use the heat rate of the most efficient CCGT currently available for the proxy CCGT plant.[56] We reject SCE's recommendation, because, as PG&E points out, real-world generators do not necessarily use the most efficient equipment, or otherwise experience the 6,500 Btu/kWh heat rate advocated by SCE and ORA.

We reaffirm the approached adopted in Resolution E-3942 that nominal MPRs, reflecting different project on-line dates, should be calculated. We also adopt the suggestion of SDG&E, CalWEA group, and PG&E that non-gas inputs should be adjusted through a published index.[57]

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[55] CalWEA group, ORA, PG&E, and SDG&E.

[56] Siemens Westinghouse 501G with heat rate of 6,500 Btu/kWh.

[57] PG&E and the CalWEA group recommend the use of a specific inflation index focused on changes in the cost to construct plants in this region, such as Global Insight's Handy-Whitman index. Other sources, such as the Northwest Power Conservation Council, may also provide useful information. We direct staff to consult such sources and explain all the sources used in the supporting materials for the 2005 MPR draft resolution.

2. Property Taxes

PG&E and SDG&E, supported by Solargenix, urge that we apply the same property tax regime to the proxy plant as applies to utilities: straight line depreciation. TURN correctly points out that the method applied to utilities by the State Board of Equalization is not necessarily applied to independent power generators by the 58 county assessors responsible for assessing property taxes in their counties. TURN does not, however, provide a method for determining how to access that information, much less how to turn it into a statewide average property tax rate. We therefore adopt the straight line method as a simplifying assumption for the property tax calculation for the proxy plant. Since it contributes a relatively small amount to the MPR (less than 1%), this simplified calculation will not materially impact the accuracy of the MPR.

3. Calculation of Line Losses and GMM

The CalWEA group asserts that the assumption in the 2004 MPR of a 98.57% Generation Meter Multiplier (GMM), should be revised. This value is derived from a sample of generator GMMs from a two-week period in December 2004. The CalWEA group notes that GMM values can be much higher during the summer months, when the transmission system is more heavily loaded. Because the utilities track the CAISO's system average GMM on a daily basis, they possess the data needed to calculate system average GMMs for all generators on the CAISO grid, over all days of the year. The CalWEA group therefore recommends using these system average GMM values for 2004 in the 2005 MPR, in order to provide more representative statewide values than the two-week snapshot of GMMs used for the 2004 MPR. No objections were raised to this proposal. We will conditionally adopt the CalWEA group's proposal and direct staff to finalize the specific method for determining GMM values and line losses in the 2005 MPR resolution.

G. Greenhouse Gas Adder

UCS, supported by ORA and Green Power, urges us to incorporate into the MPR an additional amount as an estimate of the future cost of carbon emissions or compliance with a future carbon regulatory regime. UCS argues that our adoption of the greenhouse gas adder of $8/MWh in D.04-12-048 (long-term procurement) and D.05-04-024 (avoided cost) requires the extension of the greenhouse gas adder to the MPR.

UCS misapprehends the nature of the greenhouse gas adder. UCS previously asked that the MPR calculations include a component reflecting the cost of possible future environmental regulations, such as for greenhouse gases. We rejected such costs as "too speculative" at present and stated that the MPR methodology would incorporate only "known and actual costs." (D.03-06-071, *mimeo.* at p. 23.) In D.04-12-048, we advanced the adder as a tool for the utilities to use in comparing and evaluating their procurement choices among conventionally fueled and renewable energy sources. We explicitly said that the "GHG value. . . *will not* be paid to that generator or charged to ratepayers; it is an analytic tool only. Winning bidders are to be paid the prices that they bid. Thus, the effect of the adder is to potentially change which bids and resources are selected - not to change the price of selected bids." (*Mimeo.*, at pp. 152-153.)[58]

The MPR, however, is a price, albeit a price referent. In D.04-06-015, we explained the method for calculating that price. Our extensive record on the

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[58] In D.05-04-024, we also noted that the adder "will be used as an analytic tool in the evaluation of energy efficiency programs." (*Mimeo.*, at p. 29.)

2005 MPR reveals no current price element of fixed price electricity from new gas-fired generating facilities that includes an estimate of the cost of possible future carbon regulation. Therefore, as PG&E points out, the adder "is not an out-of-pocket expense incurred by the conventional fired generator, and should not be included in the MPR."[59]

We recognize, of course, that greenhouse gas policy in California is still being developed. Since the enunciation of the greenhouse gas adder in D.04-12-048, we have continued to consider the issue of procurement incentives in our procurement docket, R.04-04-003. In Energy Action Plan II, we and the Energy Commission set out actions for the two agencies to take with respect to climate change and reduction of greenhouse gas emissions.[60] Some of those actions are in furtherance of Governor Schwarzenegger's statewide greenhouse gas reduction targets, announced in Executive Order S-3-05 on June 1, 2005.[61] We have also recently issued our own Policy Statement on Greenhouse Gas Performance Standards (October 6, 2005).[62] In its Final Transmittal of *2005 Energy Policy Report* Range of Need and Policy Recommendations to the California Public Utilities Commission (November 2005),[63] the Energy

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59 PG&E Reply to Post-Workshop Comments on 2005 Market Price Referent Issues (August 19, 2005), p. 7.

60 See http://www.cpuc.ca.gov/PUBLISHED/REPORT/51604.htm.

61 The governor's Climate Action Team is expected to complete its initial report in January 2006.

62 See http://www.cpuc.ca.gov/PUBLISHED/REPORT/50432.htm.

63 This document may be found at http://www.energy.ca.gov/2005_energypolicy/documents/index.html.

Commission endorsed the development of greenhouse gas performance standards. If and when these policy discussions are translated into regulatory programs or other sufficiently concrete market impacts, we may, as appropriate, revisit the role of accounting for greenhouse gas emissions in the MPR.[64]

H. Next Steps

1. 2005 MPR

In 2004, we directed staff to prepare the MPR calculation and release it through a joint Assigned Commissioner and Administrative Law Judge (ALJ) ruling. Parties filed comments and reply comments on the staff report releasing the MPR calculation. Staff then prepared a resolution for the adoption of the final MPR for 2004. In view of the extensive work on the 2004 MPR and the more extensive record given careful consideration by the parties for the outstanding issues for the 2005 MPR, we believe that a simpler process may be used now. We direct staff to prepare a draft resolution on the 2005 MPR, including any relevant supporting materials as attachments to the draft resolution. The draft resolution will be released, as required by D.04-06-015, after the close of all the utilities' 2005 RPS solicitations. Parties will have the usual opportunity to file comments and reply comments on the draft resolution prior to its formal consideration by the Commission. A timeline for the current RPS solicitation process, updated from the milestones in D.04-07-029, is attached as Appendix B to this decision.

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[64] We agree with SCE that including a greenhouse gas adder, thus increasing the MPR, solely as a way to preserve the pool of money available for SEPs (by reducing the number of contracts with prices above the MPR) is neither a legitimate purpose nor an allowable method for the MPR.

2. 2006 MPR

With today's decision, we complete the development of the MPR methodology that we began in D.03-06-071. We do not anticipate the need for further Commission decisions on MPR methodology. Rather, in 2006 and future years, we expect that staff will gather the information needed to make the annual calculations for the MPR and will prepare a draft resolution, with supporting materials, for party comment. The Assigned Commissioner and assigned ALJ retain discretion to seek additional party comments and/or workshops on any issues that are relevant to the preparation of the 2006 MPR, if needed.

IV. Assignment of Proceeding

Michael R. Peevey is the Assigned Commissioner and Peter V. Allen and Anne E. Simon are the assigned Administrative Law Judges (ALJs) for this proceeding.

V. Comments on Draft Decision

The draft decision of ALJ Simon in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(g)(1) and Rule 77.7 of the Rules of Practice and Procedure. Comments were filed on November 29, 2005 by the CalWEA group, Green Power, PG&E, ORA, and SCE. Reply comments were filed on December 5, 2005 by PG&E and Solargenix.[65]

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[65] On December 5, 2005, Solel Inc. filed a Motion to Intervene of Solel Inc., with proposed Reply Comments attached. On December 8, 2005 the Solar Energy Industries Association filed a Motion to Intervene of the Solar Energy Industries Association and a Motion of the Solar Energy Industries Association for Leave to File Late-Filed Reply Comments, with the proposed Reply Comments attached. The motions were denied in an Administrative Law Judge's Ruling Denying without Prejudice Motions to Intervene and Denying Motion for Leave to File Late-Filed Reply Comments (December 13, 2005). We therefore do not consider these proposed reply comments.

CalWEA Group

The CalWEA group supports the use of TODs, arguing that although the six to nine TOD periods used by the utilities do not provide the most accurate information, they do constitute the behavior of the relevant market participants. The CalWEA groups also notes what it characterizes as an inconsistency in the draft decision's treatment of the use of TODs. Whereas the draft decision identifies the goal as consistent application of TODs throughout the procurement process, it appears to allow the TODs to be "refreshed" during the bid evaluation process. The CalWEA group asserts that this undermines the effective use of TODs and urges that, if any refreshing is allowed, it be required to be at least ten business days before bids are submitted.

The intent of the draft decision was not to allow changes in the TODs themselves. The TODs may not and do not change throughout the solicitation process—from RFO through contract. Rather, the intent was to acknowledge the practice of PG&E (at least) to refresh its *valuation* of the energy delivered in a TOD period with more current market price information. This section of the draft decision has been revised to clarify this distinction.

The CalWEA group also agrees with SCE's position, discussed in more detail below, that the costs of stopping and starting the proxy CCGT should be considered in developing the capacity factor for the proxy plant. The CalWEA group contends that this position is nevertheless impractical for the MPR, since it would require more complex simulation modeling than necessary. We revise the draft decision to reflect the complexity of the start/stop issue.

Green Power

Green Power continues to support the use of TODs and continues to urge that greater granularity of TODs is desirable. As noted above, since the current market participants use the smaller number of TODs, the MPR should do so as well.

ORA

ORA makes two objections to the use of the utilities' TODs. First, ORA notes that while the TODs are public, the information underlying them is not. We will not reject the use of the existing TODs on that basis, but we make more explicit our intention to develop benchmarks based on publicly available information with which to compare TODs. Second, ORA asserts that use of the TODs in determining the capacity factor for the proxy CCGT could create an incentive to manipulate the TODs. ORA has not supported this assertion, which assumes that TODs used throughout a utility's procurement activities would be altered to affect one parameter of the MPR. To the extent that such possibilities might exist, the benchmarking process noted above should deter or detect them.

ORA also reargues its view that the MPR should incorporate a greenhouse gas adder. We expand the discussion of this point to clarify the relationship of the MPR to greenhouse gas concerns.

Finally, ORA urges that Finding of Fact 32 be eliminated. Although we do not agree with ORA's assertion that there is no record to support this finding, we also consider it not necessary to the decision and will remove it.

PG&E

PG&E points out that releasing the MPR after the development of the last utility's short list has the potential to delay release, since the utilities may take differing lengths of time to develop their short lists. Since the RPS statute only requires us to "make specific determinations of market prices after the closing date of a competitive solicitation. . .," (§ 399.14(a)(2)(A)), this delay is not necessary. We agree, and make this change. We also append an updated timeline for RPS solicitations, reflecting the current process, adapted from that in D.04-07-029.

PG&E continues to urge that the MPR be adjusted to reflect differences in the market value of the output of the proxy plant and of the renewable resource. We remain unpersuaded that this is an appropriate approach to the MPR, but note more clearly that this issue could be addressed in any review of the least cost/best fit methodology. PG&E argues that, if we do not make its suggested adjustment, we should justify it with reference to the statute. Although we do not believe that the draft decision needs to be revised either with respect to the valuation or the justification issue, we expand the discussion of the foundations of the MPR to provide a better context for the subsequent discussion.

Finally, PG&E asks us to clarify the characterization of its position on the cost of capital for the proxy plant. We revise the draft decision to make this change.

SCE

SCE requests that we not require it to conform its TOD methodology to that of PG&E and SDG&E for the 2005 RPS solicitation, but allow it to make the change for 2006. Although this will result in an anomaly among the utilities for 2005, we are persuaded that, as CalWEA suggests, consistency of application of TODs within one utility's solicitation is more important than consistency across utilities for 2005. We therefore revise the draft decision to alter SCE's compliance obligations with respect to TODs.

SCE also argues that we should take account of the impact of the costs of starting and stopping the proxy CCGT if the capacity factor is less than 92%. As CalWEA notes, it would be useful but difficult to implement this suggestion. We revise the draft decision to direct staff to consider making such an adjustment, within certain parameters.

In addition to revisions made in response to comments, we have made other minor corrections and clarifications to the draft decision.

Findings of Fact

1. The 2004 MPR methodology provides a reasonable basis for development of an MPR methodology for 2005 and subsequent years.

2. It is not necessary for the Commission to construct a 20-year forward gas contract for the MPR calculation.

3. The Gas Stipulation entered into by PG&E, California Cogeneration Council, CalWEA, Central California Power, SDG&E, and SCE is supported by the record.

4. Modifications to the 2004 MPR gas forecast outlined in the Gas Stipulation are appropriate for Years 1-6 in the MPR gas forecast for 2005.

5. The annual escalation approach used after the last year of NYMEX data, part of the 2004 MPR gas forecasting methodology, potentially distorts the gas prices forecasted for Years 7- 20.

6. It is reasonable to modify the 2004 gas forecast methodology to reflect a three-year straight line blending between the near-term (Years 1–6) and the long-term (Years 7-20), effectively retaining the absolute value of gas price forecasts from fundamentals-based sources.

7. The use of TOD profiles developed by each utility will improve the accuracy and effectiveness of the MPR.

8. The use of TOD profiles will eliminate the need to calculate an MPR for a peaker proxy plant.

9. The use of TOD profiles will eliminate the need to calculate a "blended" MPR for a proxy product that is neither baseload nor peaking.

10. The methods used by PG&E and SDG&E to calculate their TODs are appropriate for use for the MPR.

11. SCE's proposed method of using a QF-based TOD is not appropriate for use for the MPR.

12. SCE should revise its TODs in future solicitations using forward market data in a manner similar to that of PG&E and SDG&E.

13. It is reasonable to use TODs consistently throughout the RPS procurement process, including bid prices, least cost/best fit bid evaluation, and SEP determination.

14. It is reasonable to develop a method for benchmarking and evaluating the utilities' TODs, using publicly available data.

15. The "mid-point" approach is appropriate for selecting an input value from a reasonable range of values for the 2005 MPR.

16. It is reasonable to use market survey data, as relevant, to determine appropriate inputs for use in the MPR calculation.

17. It is reasonable to use secondary market data related to costs for the proxy plant in the MPR calculation only if the data have been reviewed in a formal Commission proceeding.

18. It is reasonable to limit the data on installed capital costs for the MPR calculation to costs in California.

19. It is reasonable to adopt the General Electric F-Series gas turbine as a statewide CCGT proxy.

20. It is reasonable to allow staff to consult published sources of information about operational characteristics of the proxy plant (*e.g.*, the proxy plant turbine) that may include information about facilities outside California.

21. It is reasonable to assume balance sheet financing for the MPR proxy plant.

22. It is reasonable to treat the MPR proxy plant as having a ratio of debt to equity of 50%/50%.

23. It is reasonable to assume that the risk profile of the proxy plant falls somewhere between that of a merchant generator (selling into the market without a long-term contract) and a utility.

24. It is reasonable to use a survey of industrial companies in the Standard and Poor's 500 index having risk factors similar to those of independent power producers to determine the weighted average cost of capital for the proxy plant.

25. It is reasonable to use an averaging of utility-specific TOD profiles to calculate a statewide capacity factor for the proxy plant.

26. It is reasonable to assign some heat rate penalty (measured in Btu) for dry cooling for the proxy plant.

27. It is reasonable to consider whether to assign some heat rate penalty (measured in Btu) for a capacity factor less than 92% for the proxy plant.

28. It is reasonable to assign some heat rate penalty (measured in Btu) for degradation of performance of the proxy plant.

29. It is reasonable to calculate nominal MPRs reflecting different project on-line dates.

30. It is reasonable to assume that capital costs fo r the proxy plant should be escalated until 2010 and then held constant to reflect the fact that increased efficiencies will offset incremental capital costs.

31. The greenhouse gas adder identified in D.04-12-048 was developed to allow comparisons among procurement options.

32. The greenhouse gas adder is not currently an element of the long-term market price of electricity in California.

33. The most efficient way to release the MPR for 2005 is by staff preparation of a draft resolution, including relevant supporting documentation.

Conclusions of Law

1. The methodology developed for the 2004 MPR, with the improvements set forth in this decision, should be used in 2005.

2. The Gas Stipulation is supported by the record, consistent with law, and in the public interest.

3. A method for benchmarking and evaluating the utilities' TODs, using publicly available data, should be developed.

4. The greenhouse gas adder developed in D.04-12-048 should not be an element of the MPR calculation for 2005.

5. The calculation of the 2005 MPR should be released by staff preparation of a draft resolution after all utility solicitations have been closed.

6. In order to allow the calculation of the 2005 MPR to proceed expeditiously, this order should be effective immediately.

INTERIM ORDER

IT IS ORDERED that:

1. The Stipulation Regarding Guiding Principles and Short-Term Gas Price Forecast Methodology for the 2005 Market Price Referent (MPR) Calculation entered into September 7, 2005, by Pacific Gas and Electric Company (PG&E), California Cogeneration Council, California Wind Energy Association, Central California Power, San Diego Gas & Electric Company, and Southern California Edison Company (Edison) is adopted.

2. The 2005 calculation of the MPR shall be undertaken by staff in accordance with the directives in this decision.

3. The 2005 calculation of the MPR shall be released by staff preparation of a draft resolution after all utility solicitations have been closed, and the last utility short list is developed.

4. Not later than January 10, 2006, Edison shall file and serve its 2006 time of delivery (TOD) profiles calculated by the method used by PG&E for its TOD profiles.

5. The Assigned Commissioner and assigned administrative law judge shall set a schedule for developing a method for benchmarking and evaluating the utilities' TOD profiles, using publicly available data.

This order is effective today.

Dated December 15, 2005, at San Francisco, California.

MICHAEL R. PEEVEY
President
GEOFFREY F. BROWN
SUSAN P. KENNEDY
JOHN A. BOHN
Commissioners

Commissioner Dian M. Grueneich recused herself from this agenda item and was not part of the quorum in its consideration.

APPENDIX A

STIPULATION REGARDING SHORT-TERM GAS PRICE FORECAST METHODOLOGY FOR 2005 MARKET PRICE REFERENT IN RULEMAKING 04-04-026

I. AGREEMENT

In accordance with Rule 51 et seq. of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission), the parties to this stipulation (Stipulating Parties) file this document and recommend that the Commission adopt the agreed-upon methodology for establishing the short-term natural gas price forecast for use in calculating the 2005 Market Price Referent (MPR). The parties' stipulation to the general principles proposed in the Administrative Law Judge's Ruling of August 9, 2005 is set out in Table 1.[1] The parties' stipulation regarding proposed sources and methodologies to shape the 1-6 year short-term period is summarized in Table 2. Both tables are an integral part of this stipulation as to the methodology for setting the price of natural gas during the Years 1 through 6 as an input to the 2005 MPR (Short-Term Gas Price Stipulation).

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1 Southern California Edison Company only stipulates to one of the general principles proposed in the Administrative Law Judge's Ruling of August 9, 2005 as set out in Table 1 – that market data should be used to the extent possible. Southern California Edison Company does not stipulate to the other general principles proposed in the Administrative Law Judge's Ruling of August 9, 2005, and does not agree that these principles should be used in formulating the 2005 MPR gas price forecast.

II. PARTIES

The parties to the Short-Term Gas Price Stipulation are California Cogeneration Council and California Wind Energy Associates (collectively, CCC), Central California Power (CCP), San Diego Gas & Electric Company (SDG&E), Southern California Edison (SCE), and Pacific Gas and Electric Company (PG&E).

III. CONDITIONS

The Stipulating Parties agree to the following conditions:

1. This embodies the entire understanding and agreement of the Stipulating Parties with respect to the matters described, and it supersedes prior oral or written agreements, principles, negotiations, statements, representations, or understandings among the Stipulating Parties with respect to those matters.

2. This Short-Term Gas Price Stipulation represents a compromise among the Stipulating Parties' respective litigation positions, not an agreement to or an endorsement of disputed facts and law presented by the Stipulating Parties in this proceeding.

3. Except where noted, the Stipulating Parties agree that this Short-Term Gas Price Stipulation is reasonable in light of the parties' assertions, consistent with law, and in the public interest, in accordance with Rule 51.1(e).

4. The Stipulating Parties agree that no provision of this Short-Term Gas Price Stipulation shall be construed against any Stipulating Party because that Stipulating Party or its counsel or advocate drafted the provision.

5. This Short-Term Gas Price Stipulation may be amended or changed only by a written agreement signed by the Stipulating Parties.

6. Except where noted, the Stipulating Parties shall jointly request and actively support timely Commission approval of this Short-Term Gas Price Stipulation. Active support shall include written and oral testimony if testimony is required, briefing if briefing is required, comments on the proposed decision, advocacy to Commissioners and their advisors as needed, and other appropriate means as needed to obtain the requested approval.

7. The Stipulating Parties intend the Short-Term Gas Price Stipulation to be interpreted and treated as a unified, integrated agreement. In the event the Commission rejects or modifies this Short-Term Gas Price Stipulation, the Stipulating Parties reserve their rights under Rule 51.7.

IV. HISTORY

The objective of this phase of R.04-04-026 is to identify the appropriate inputs and methodology for the calculation of the 2005 MPR. The Administrative Law Judge's (ALJ) Ruling Setting Schedule for Consideration of 2005 Market Price Referent (MPR) Issues (May 24, 2005), identified the issue of gas inputs as a matter of highest priority for the calculation of the 2005 MPR and provided that information about gas price inputs and gas price forecast modeling would be presented for the

Commission's consideration at a workshop held on June 20 and 21, 2005. Parties accordingly filed pre-workshop briefs on June 10.

After the workshop was held, in a ruling dated July 7, the ALJ observed, "As a result of the workshops, it appears that the process of setting the 2005 MPR would benefit from more detailed suggestions to the parties about topics that could be covered in the briefs." The ruling requested the parties to consider whether the Commission's adoption of gas inputs and the gas price forecast methodology should be guided by certain principles. It also asked parties to explain in detail the basis for previously made assertions about gas price inputs. In accordance with the ALJ's schedule, parties filed opening and reply briefs on July 29 and August 12, respectively. The schedule also suggested that any stipulations regarding workshop issues should be filed on August 10.

After providing notice to all parties pursuant to Rule 51.1(b) on August 8, 2005, PG&E hosted an initial conference to discuss the potential settlement of gas inputs on August 15, 2005, from 2:30 p.m. to 5:00 p.m. at PG&E's office in San Francisco; free access was also provided for parties to participate by phone. A similar follow-up conference was held on September 1, 2005. Copies of the notices are attached.

As a result of these discussions, on September 1, 2005, the Stipulating Parties (CCC, CCP, SCE, SDG&E, and PG&E) reached an agreement on the short term gas price inputs for the 2005 MPR.

V. TERMS

1. The Stipulating Parties, with the exception of SCE, agree that the Commission should observe the general principles stated in Table 1 to formulate the 2005 MPR gas price forecast. As shown by Table 1, SCE stipulates to the general principle that market data should be used to the extent possible, but does not agree that the other general principles in Table 1 should be observed in formulating the 2005 MPR gas price forecast.

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Table 1 – General Principles to be Used in Formulating the 2005 MPR Natural Gas Price Forecast

(proposed principles in bold. Changes to original July 7 principles in bold italics,):

As originally proposed in the July 7, 2005 ALJ Ruling following June 2005 MPR Workshops	As agreed to by participating Parties in August 15, 2005 Rule 51.1 Conference	Stipulating Parties
1. Reflects behavior of market participants.	**1. Reflects behavior of market participants.**	CCC/CalWEA, SDG&E, PG&E, CCP. <u>*SCE does not.*</u>
2. Market data should be used to the extent possible.	**2. Market data should be used to the extent possible.**	CCC/CalWEA, SCE, SDG&E, PG&E, CCP.
3. For longer term contracts that extend beyond available market data, forecasts should exhibit a clear relationship to fundamental costs.	**3. For shorter-term contracts, forecast data should be verified against forward market data; for longer-term contracts that extend beyond available market data, forecasts should be benchmarked against fundamental costs and/or historical market data.**	CCC/CalWEA, SDG&E, PG&E, CCP. <u>*SCE does not.*</u>
4. Methodology should be consistent with evaluation of other products.	**4. Methodology should be consistent with evaluation of other products.**	CCC/CalWEA, SDG&E, PG&E, CCP. <u>*SCE does not.*</u>
5. Methodology should be verifiable using historical data.		
6. Methodology should be consistent with previous regulatory decisions.	**6. Methodology should be consistent with previous regulatory decisions.**	CCC/CalWEA, SDG&E, PG&E, CCP. <u>*SCE does not.*</u>

<u>Legend of Stipulating Parties</u>

- CCC/CalWEA = California Cogeneration Council/California Wind Energy Association
- SDG&E = San Diego Gas and Electric Company
- SCE = Southern California Edison
- PG&E = Pacific Gas and Electric Company
- CCP = Central California Power

2. The Stipulating Parties agree that the inputs contained in Table 2 should be used to calculate the gas prices forecast for Years 1 through 6 of the 2005 MPR.

Table 2
Proposed Sources and Methodologies to Shape the 1 to 6 year Short Term Period

(Bold indicates changes from 2004 methodology for Years 1 through 6)

Issue	2004 MPR Methodology	Proposed 2005 MPR Methodology	Stipulating Parties
Surcharges (e.g., generator gas transmission fee, franchise fee, shrinkage)	Gas prices should be estimated at the proxy power plant burner tip (per CPUC Staff Report on 2004 MPR, February 10, 2005, page 6)	Gas prices should be estimated at the proxy power plant burner tip (per CPUC Staff Report on 2004 MPR, February 10, 2005, page 6)	CCC/CalWEA, SDG&E, SCE, PG&E, CCP.
Hedging costs—now known as **Transaction Costs**	$0.082/MMBtu, consisting of one-half the bid/ask spread and a collateral carrying cost ($0.071 + $0.011, respectively) (per D.04-06-015, page 27)	$0.082/MMBtu, consisting of one-half the bid/ask spread and a collateral carrying cost ($0.071 + $0.011, respectively) (per D.04-06-015, page 27)	CCC/CalWEA, SDG&E, SCE, PG&E, CCP.
Basis (location differential) o 50% SoCal Border plus generator transport o 50% PG&E Citygate plus generator transport	NYMEX ClearPort (~2 years), then extend last year of actual basis quotes as a constant for remaining years.	NYMEX ClearPort (~2 years), then extend last year of actual basis quotes as a constant for remaining years.	CCC/CalWEA, SDG&E, SCE, PG&E. CCP abstains. *CCC/CalWEA recommends monitoring the long-term basis adjustment to ensure consistency of short term and long term*

			trends.
Primary Data Source of Commodity Price	NYMEX Henry Hub futures	NYMEX Henry Hub futures	CCC/CalWEA, SDG&E, SCE, PG&E. CCP abstains.
Time Length / Tenor	Minimum 5 years of NYMEX Henry Hub futures, with CPUC staff discretion on the sixth year.	Minimum 5 years of NYMEX Henry Hub futures, with CPUC staff discretion on the sixth year.	CCC/CalWEA, SDG&E, SCE, PG&E, CCP.
Averaging Period and Calculation Start Date	60-trading-day averaging period, ending with bid due date of PG&E, calculated once for all IOUs.	**22**-trading-day averaging period, ending with **short-list date of the last IOU to report**, calculated for all 3 IOUs.	CCC/CalWEA, SDG&E, SCE, PG&E, CCP.

<u>Legend of Stipulating Parties</u>

- CCC/CalWEA = California Cogeneration Council/California Wind Energy Association
- SDG&E = San Diego Gas and Electric Company
- SCE = Southern California Edison
- PG&E = Pacific Gas and Electric Company
- CCP = Central California Power

3. Except where noted, the Stipulating Parties agree that this outcome is reasonable, consistent with law, and in the public interest.

VI. EXECUTION

This Short-Term Gas Price Stipulation shall become effective among the Stipulating Parties on the date the last Stipulating Party executes the Short-Term Gas Price Stipulation as indicated below. In witness whereof, intending to be legally bound, the Stipulating Parties hereto have duly executed this Short-Term Gas Price Stipulation on behalf of the Stipulating Parties they represent. This

Short-Term Gas Price Stipulation is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Stipulating Party represented.

CALIFORNIA COGENERATION COUNCIL AND CALIFORNIA WIND ENERGY ASSOCIATION

By: /s/ R. Thomas Beach by E. Lee

Name: R. Thomas Beach

Title: Crossborder Energy for CCC and CalWEA

Date: September 7, 2005

CENTRAL CALIFORNIA POWER

By: /s/ Joseph Langenberg by E. Lee

Name: Joseph Langenberg

Title: Principal

Date: September 7, 2005

SAN DIEGO GAS & ELECTRIC COMPANY

By: /s/ Meredith Allen by E. Lee

Name: Meredith Allen

Title: Attorney

Date: September 6, 2005

SOUTHERN CALIFORNIA EDISON COMPANY

By: /s/ Cathy Karlstad by E. Lee

Name: Cathy Karlstad

Title: Attorney

Date: September 7, 2005

PACIFIC GAS AND ELECTRIC COMPANY

By: /s/ Evelyn C. Lee

Name: Evelyn C. Lee

Title: Attorney

Date: September 7, 2005

Appendices Follow

Appendix 1

Notice for August 15 conference

From: Ryzhaya, Katherine
Sent: Monday, August 08, 2005 5:26 PM
To: Livingston-nunley, Grace; 'jmckinney@thelenreid.com'; 'lennyh@evomarkets.com'; Kolb, Marc E; Winn, Valerie J; 'jonwelner@paulhastings.com'; 'info@tobiaslo.com'; 'cem@newsdata.com'; 'snuller@ethree.com'; 'robertgex@dwt.com'; Law CPUC Cases; Barry, Donna L; 'nprocos@alamedapt.com'; 'keithwhite@earthlink.net'; 'robert.boyd@ps.ge.com'; 'dietrichlaw@earthlink.net'; 'ramonag@ebmud.com'; 'ceyap@earthlink.net'; 'mrw@mrwassoc.com'; 'bepstein@fablaw.com'; 'dweisz@cera.com'; 'rschmidt@bartlewells.com'; 'rhwiser@lbl.gov'; 'derek@denniston.com'; 'brbarkovich@earthlink.net'; 'rmccann@umich.edu'; 'vwood@smud.org'; 'cmkehrein@ems-ca.com'; 'e-recipient@caiso.com'; 'e-recipient@caiso.com'; 'grosenblum@caiso.com'; 'lpark@navigantconsulting.com'; 'vfleming@navigantconsulting.com'; 'karly.mccrory@rweschottsolar.us'; 'dougdpucmail@yahoo.com'; 'kevin@solardevelop.com'; 'mclaughlin@braunlegal.com'; 'dkk@eslawfirm.com'; 'kdw@woodruff-expert-services.com'; 'wwwesterfield@stoel.com'; 'rroth@smud.org'; 'karen@klindh.com'; 'dws@r-c-s-inc.com'; 'LAdocket@cpuc.ca.gov'; 'as2@cpuc.ca.gov'; 'ajo@cpuc.ca.gov'; 'aes@cpuc.ca.gov'; 'dil@cpuc.ca.gov'; 'dsh@cpuc.ca.gov'; 'jf2@cpuc.ca.gov'; 'ltr@cpuc.ca.gov'; 'lp1@cpuc.ca.gov'; 'mrl@cpuc.ca.gov'; 'nao@cpuc.ca.gov'; 'psd@cpuc.ca.gov'; 'pva@cpuc.ca.gov'; 'pha@cpuc.ca.gov'; 'sed@cpuc.ca.gov'; 'rmiller@energy.state.ca.us'; 'skorosec@energy.state.ca.us'; 'JMcMahon@navigantconsulting.com'; 'hraitt@energy.state.ca.us'; 'kzocchet@energy.state.ca.us'; 'wsm@cpuc.ca.gov'; 'garson_knapp@fpl.com'; 'doug.larson@pacificorp.com'; 'msimmons@sierrapacific.com'; 'PUCservice@manatt.com'; 'msnow@manatt.com'; 'msnow@manatt.com'; 'pucservice@manatt.com'; 'klatt@energyattorney.com'; 'douglass@energyattorney.com'; 'berj.parseghian@sce.com'; 'fortlieb@sandiego.gov'; 'meallen@sempra.com'; 'wiebe@pacbell.net'; 'hal@rwitz.net'; 'sara@oakcreekenergy.com'; 'cpc1993@hotmail.com'; 'jaturnbu@ix.netcom.com'; 'pepper@cleanpowermarkets.com'; 'wblattner@semprautilities.com'; 'joe.como@sfgov.org'; 'mzafar@semprautilities.com'; 'freedman@turn.org'; 'kpp@cpuc.ca.gov'; 'rsa@a-klaw.com'; 'jpross@votesolar.org'; 'placourciere@thelenreid.com'; Lee, Evelyn C (Law); 'bcragg@gmssr.com'; 'jkarp@whitecase.com'; 'meganmmyers@yahoo.com'; 'ssmyers@att.net'; 'jhamrin@resource-solutions.org'; 'jchamberlin@sel.com'; 'lsherif@calpine.com'; 'jackp@calpine.com'; 'wbooth@booth-law.com'; 'bill.chen@constellation.com'; 'gmorris@emf.net'; 'jgalloway@ucsusa.org'; 'clyde.murley@comcast.net'; 'nrader@calwea.org'; 'tomb@crossborderenergy.com'; 'arno@energyinnovations.com'; 'johnrredding@earthlink.net'; 'janmcfar@sonic.net'; 'steven@iepa.com'; 'tomstarrs@b-e-f.org'; 'cynthia.schultz@pacificorp.com'; 'bshort@ridgewoodpower.com'; 'csmoots@perkinscoie.com'; 'rberliner@manatt.com'; 'obrienc@sharpsec.com'; 'porter@exeterassociates.com'; 'mcollins@icc.state.il.us'; 'abiecunasjp@bv.com'; 'pletkarj@bv.com'; 'meyertm@bv.com'; 'kjsimonsen@ems-ca.com'; 'dsaul@solel.com'; 'dnorris@sppc.com'; 'jgreco@caithnessenergy.com'; 'jozenne@semprautilities.com'; 'steve@energyinnovations.com'; 'jackmack@suesec.com'; 'case.admin@sce.com'; 'j.eric.isken@sce.com'; 'gary.allen@sce.com'; 'woodrujb@sce.com'; 'lizbeth.mcdannel@sce.com'; 'lwrazen@sempraglobal.com'; 'tcorr@sempra.com'; 'ygross@sempraglobal.com'; 'liddell@energyattorney.com'; 'amabed@semprautilities.com'; 'scott.anders@sdenergy.org'; 'susan.freedman@sdenergy.org'; 'centralfiles@semprautilities.com'; 'jcervantes@sandiego.gov'; 'jleslie@luce.com'; 'bill.owen@adelphia.net'; 'csteen@bakerlaw.com'; 'jleblanc@bakerlaw.com'; 'mjskowronski@inlandenergy.com'; 'olsen@avenuecable.com'; 'thunt@cecmail.org'; 'mdjoseph@adamsbroadwell.com'; 'diane_fellman@fpl.com'; 'nsuetake@turn.org'; 'mhyams@sfwater.org'; 'dbachrach@nrdc.org'; 'filings@a-klaw.com'; 'dickerson07@fscgroup.com'; Lucha, Ed; 'dgulino@ridgewoodpower.com'; 'keith.mccrea@sablaw.com'
Cc: Ryzhaya, Katherine
Subject: 2005 MPR: Notice of Conference pursuant to Rule 51.1 (b)

Notice to Parties to Rulemaking (R.) 04-04-026 at the request of Energy Division staff, California Public Utilities Commission:

Notice of Conference pursuant to Rule 51.1 subsection (b) of the CPUC's Rules of Practice and Procedure

On August 15, 2005, Pacific Gas and Electric (PG&E) will host a breakout session to identify and discuss the appropriate methodology for Establishing Short-term Gas Inputs for Proxy Plant for use in the development of the 2005 Market Price Referent (MPR) natural gas price methodology. This session augments the recently convened workshops and post-workshop briefs on the Methodology to Modify the 2004 Market Price Referent (MPR) for use in the 2005 Renewable Portfolio Standard (RPS) procurement process. The goal of the session is to facilitate and document consensus on as many assumptions as possible prior to the filing of the reply briefs, which are due on August 19th, as required by ALJ Simon's July 7th Ruling. In the event that parties stipulate to one or more material issues in the proceeding, the stipulation would be proposed for adoption by the Commission in accordance with Rule 51.1.

Participants interested in presenting a proposal are encouraged to circulate materials to the service list prior to the session.

A detailed agenda is provided below for your review. For security reasons, advance registration is required by August 11, 2005; it is better to register even if your attendance is not absolutely certain. Please contact Marc Kolb [415-973-0206 or MEKd@pge.com] with any questions.

August 15, 2005
2:30-5:00 P.M.
Pacific Gas and Electric Company
245 Market Street, Room 1411
San Francisco, CA 94105
(Participants will be greeted in the Lobby)

Agenda for 2005 MPR
Short-term Gas Price Forecast Methodology
Rule 51.1 Conference

Facilitator:
Harold Pestana, PG&E

Purpose:

This breakout session (or conference) is intended to produce consensus on the MPR short-term gas price forecast methodology. It is anticipated that many, if not most, outstanding issues will be resolved through the breakout session (or conference) process. Parties should consider a mechanism for identifying agreed-upon issues and solutions.[1]
[1] For example, a stipulation pursuant to Rule 51.1 of the Commission's Rules of Practice and Procedures.

I. Introductions

II. Identifying the scope of subgroup deliverables. At a minimum these deliverables should include:

- A 2005 MPR short-term gas price proposal, with elements to which all parties can agree.
- Discussion and agreement on Section 2 of Attachment 1 of ALJ Simon's July 7th Ruling Setting Schedule for Briefs Following 2005 Market Price Referent Workshops. (Certain attributes of Section 1 of Attachment 1, as they pertain to the short-to-mid term gas price forecast methodology, will also be addressed.)

III. Proposals:

- Comparison of 2005 Proposal against 2004 methodology
- Discuss and resolve gaps and attempt to come to agreement among all parties.

IV. Group to discuss results / next steps.

- Discussion will result in adoption of a set of assumptions, an identification of remaining issue gaps if any, and follow-up items for parties to address.

Katherine Ryzhaya
(415) 972-5011
KARp@pge.com

Appendix 2

Notice for September 1, 2005 Conference

"Kolb, Marc E" <MEKd@pge.com>

08/29/2005 07:46 PM

To: "Tom Beach" <tomb@crossborderenergy.com>, "Livingston-nunley, Grace" <GXL2@pge.com>, <jmckinney@thelenreid.com>, <lennyh@evomarkets.com>, "Winn, Valerie J" <VJW3@pge.com>, <jonwelner@paulhastings.com>, <info@tobiaslo.com>, <cem@newsdata.com>, <snuller@ethree.com>, <robertgex@dwt.com>, "Law CPUC Cases" <CPUCCases@pge.com>, "Barry, Donna L" <DLBf@pge.com>, <nprocos@alamedapt.com>, <keithwhite@earthlink.net>, <robert.boyd@ps.ge.com>, <Michael.Whatley@SCE.com>, "Patrick McGuire \(Patrick McGuire\)" <patrickm@crossborderenergy.com>, <dietrichlaw@earthlink.net>, <ramonag@ebmud.com>, <ceyap@earthlink.net>, <mrw@mrwassoc.com>, <bepstein@fablaw.com>, <dweisz@cera.com>, <dsh@cpuc.ca.gov>, <Cathy.Karlstad@SCE.com>, <rschmidt@bartlewells.com>, <rhwiser@lbl.gov>, <derek@denniston.com>, <richard.davis@SCE.com>, <brbarkovich@earthlink.net>, <james.read@brattle.com>, <rmccann@umich.edu>, <vwood@smud.org>, <cmkehrein@ems-ca.com>, <e-recipient@caiso.com>, <e-recipient@caiso.com>, <grosenblum@caiso.com>, <lpark@navigantconsulting.com>, <vfleming@navigantconsulting.com>, <karly.mccrory@rweschottsolar.us>, <dougdpucmail@yahoo.com>, <kevin@solardevelop.com>, <mclaughlin@braunlegal.com>, <dkk@eslawfirm.com>, <kdw@woodruff-expert-services.com>, <wwwesterfield@stoel.com>, <rroth@smud.org>, <karen@klindh.com>, <dws@r-c-s-inc.com>, <LAdocket@cpuc.ca.gov>, <as2@cpuc.ca.gov>, <ajo@cpuc.ca.gov>, <aes@cpuc.ca.gov>, <dil@cpuc.ca.gov>, <dsh@cpuc.ca.gov>, <jf2@cpuc.ca.gov>, <ltr@cpuc.ca.gov>, <lp1@cpuc.ca.gov>, <mrl@cpuc.ca.gov>, <nao@cpuc.ca.gov>, <psd@cpuc.ca.gov>, <pva@cpuc.ca.gov>, <pha@cpuc.ca.gov>, <sed@cpuc.ca.gov>, <rmiller@energy.state.ca.us>, <skorosec@energy.state.ca.us>, <JMcMahon@navigantconsulting.com>, <hraitt@energy.state.ca.us>, <kzocchet@energy.state.ca.us>, <wsm@cpuc.ca>

cc: <gmorris@emf.net>, <psd@cpuc.ca.gov>, <rmm@cpuc.ca.gov>, <nao@cpuc.ca.gov>, <mrl@cpuc.ca.gov>, <derek@denniston.com>, <cathy.karlstad@SCE.com>, <Michael.Whatley@SCE.com>, <james.read@brattle.com>, <patrickm@crossborderenergy.com>, "Lee, Evelyn C \(Law\)" <ECL8@pge.com>, "Pestana, Harold \(GES\)" <HJP5@pge.com>, "Strauss, Todd \(PCERD\)" <TxSq@pge.com>, "Hatton, Curtis A \(PCERD\)" <CAH9@pge.com>, <ren@ethree.com>, <mjskowronski@inlandenergy.com>, <rpurves@sempratutilities.com>, <meallen@sempra.com>

Subject: RE: 2005 MPR: Aug 15th Conference **new conf call date/time** pursuant to Rule 51.1 (b) -- Summary of Agreement / Invitation to Join Stipulation

In light of conflicting activities noted below by Tom Beach, we propose to reschedule the conference call for **Thursday, September 1st from 1:00 P.M. to 2:30 P.M.**

Conf call number: 1-877-241-3594
Participant Code: 305947

If interested in joining in the conference call or this stipulation, please contact Katherine Ryzhaya, <karp@pge.com> 415-972-5011 or Marc Kolb <mekd@pge.com>, 415-973-0206 by **Tuesday, August 30.**

From: Tom Beach [mailto:tomb@crossborderenergy.com]
Sent: Friday, August 26, 2005 12:52 PM
To: Kolb, Marc E; Livingston-nunley, Grace; jmckinney@thelenreid.com; lennyh@evomarkets.com; Winn, Valerie J; jonwelner@paulhastings.com; info@tobiaslo.com; cem@newsdata.com; snuller@ethree.com; robertgex@dwt.com; Law CPUC Cases; Barry, Donna L; nprocos@alamedapt.com; keithwhite@earthlink.net; robert.boyd@ps.ge.com; Michael.Whatley@SCE.com; 'Patrick McGuire (Patrick McGuire)'; dietrichlaw@earthlink.net; ramonag@ebmud.com; ceyap@earthlink.net; mrw@mrwassoc.com; bepstein@fablaw.com; dweisz@cera.com; dsh@cpuc.ca.gov; Cathy.Karlstad@SCE.com; rschmidt@bartlewells.com; rhwiser@lbl.gov; derek@denniston.com; richard.davis@SCE.com; brbarkovich@earthlink.net; james.read@brattle.com; rmccann@umich.edu; vwood@smud.org; cmkehrein@ems-ca.com; e-recipient@caiso.com; e-recipient@caiso.com; grosenblum@caiso.com; lpark@navigantconsulting.com; vfleming@navigantconsulting.com; karly.mccrory@rweschottsolar.us; dougdpucmail@yahoo.com; kevin@solardevelop.com; mclaughlin@braunlegal.com; dkk@eslawfirm.com; kdw@woodruff-expert-services.com; wwwesterfield@stoel.com; rroth@smud.org; karen@klindh.com; dws@r-c-s-inc.com; LAdocket@cpuc.ca.gov; as2@cpuc.ca.gov; ajo@cpuc.ca.gov; aes@cpuc.ca.gov; dil@cpuc.ca.gov; dsh@cpuc.ca.gov; jf2@cpuc.ca.gov; ltr@cpuc.ca.gov; lp1@cpuc.ca.gov; mrl@cpuc.ca.gov; nao@cpuc.ca.gov; psd@cpuc.ca.gov; pva@cpuc.ca.gov; pha@cpuc.ca.gov; sed@cpuc.ca.gov; rmiller@energy.state.ca.us; skorosec@energy.state.ca.us; JMcMahon@navigantconsulting.com; hraitt@energy.state.ca.us; kzocchet@energy.state.ca.us; wsm@cpuc.ca.gov; garson_knapp@fpl.com; doug.larson@pacificorp.com; msimmons@sierrapacific.com; PUCservice@manatt.com; msnow@manatt.com; msnow@manatt.com; pucservice@manatt.com; klatt@energyattorney.com; douglass@energyattorney.com; berj.parseghian@SCE.com; fortlieb@sandiego.gov; meallen@sempra.com; wiebe@pacbell.net; hal@rwitz.net; sara@oakcreekenergy.com; cpc1993@hotmail.com; jaturnbu@ix.netcom.com; pepper@cleanpowermarkets.com; wblattner@semprautilities.com; joe.como@sfgov.org; mzafar@semprautilities.com; freedman@turn.org; kpp@cpuc.ca.gov; rsa@a-klaw.com; jpross@votesolar.org; placourciere@thelenreid.com; Lee, Evelyn C (Law); bcragg@gmssr.com; jkarp@whitecase.com; meganmmyers@yahoo.com; ssmyers@att.net; jhamrin@resource-solutions.org; jchamberlin@sel.com; lsherif@calpine.com; jackp@calpine.com; wbooth@booth-law.com; bill.chen@constellation.com; gmorris@emf.net; jgalloway@ucsusa.org; clyde.murley@comcast.net; nrader@calwea.org; arno@energyinnovations.com; johnrredding@earthlink.net; janmcfar@sonic.net; steven@iepa.com; tomstarrs@b-e-f.org; cynthia.schultz@pacificorp.com; bshort@ridgewoodpower.com; csmoots@perkinscoie.com; rberliner@manatt.com; obrienc@sharpsec.com; porter@exeterassociates.com; mcollins@icc.state.il.us; abiecunasjp@bv.com; pletkarj@bv.com; meyertm@bv.com; kjsimonsen@ems-ca.com; dsaul@solel.com; dnorris@sppc.com; jgreco@caithnessenergy.com; jozenne@semprautilities.com; steve@energyinnovations.com; jackmack@suesec.com;

case.admin@SCE.com; j.eric.isken@SCE.com; gary.allen@SCE.com; woodrujb@SCE.com; lizbeth.mcdannel@SCE.com; lwrazen@sempraglobal.com; tcorr@sempra.com; ygross@sempraglobal.com; liddell@energyattorney.com; amabed@semprautilities.com; scott.anders@sdenergy.org; susan.freedman@sdenergy.org; centralfiles@semprautilities.com; jcervantes@sandiego.gov; jleslie@luce.com; bill.owen@adelphia.net; csteen@bakerlaw.com; jleblanc@bakerlaw.com; mjskowronski@inlandenergy.com; olsen@avenuecable.com; thunt@cecmail.org; mdjoseph@adamsbroadwell.com; diane_fellman@fpl.com; nsuetake@turn.org; mhyams@sfwater.org; dbachrach@nrdc.org; filings@a-klaw.com; dickerson07@fscgroup.com; Lucha, Ed; dgulino@ridgewoodpower.com; keith.mccrea@sablaw.com
Cc: gmorris@emf.net; psd@cpuc.ca.gov; rmm@cpuc.ca.gov; nao@cpuc.ca.gov; mrl@cpuc.ca.gov; derek@denniston.com; cathy.karlstad@SCE.com; Michael.Whatley@SCE.com; james.read@brattle.com; patrickm@crossborderenergy.com; Lee, Evelyn C (Law); Pestana, Harold (GES); Strauss, Todd (PCERD); Hatton, Curtis A (PCERD); ren@ethree.com; mjskowronski@inlandenergy.com; rpurves@semprautilities.com; meallen@sempra.com
Subject: RE: 2005 MPR: Aug 15th Conference pursuant to Rule 51.1 (b) -- Summary of Agreement / Invitation to Join Stipulation

Marc –

A number of the parties that are involved in the MPR case are also working hard to produce avoided cost testimony by next Wednesday in R. 04-04-025 and R. 04-04-003. We are among those parties, and are unlikely to be able to review this stipulation in any detail until Thursday. I am hopeful that CCC / CalWEA / CBEA can join a stipulation on this component of the MPR calculation, but we will need at least a few more days to review it.

Thanks for your consideration,

Tom Beach

-----Original Message-----
From: Kolb, Marc E [mailto:MEKd@pge.com]
Sent: Friday, August 26, 2005 11:30 AM
To: Livingston-nunley, Grace; jmckinney@thelenreid.com; lennyh@evomarkets.com; Winn, Valerie J; jonwelner@paulhastings.com; info@tobiaslo.com; cem@newsdata.com; snuller@ethree.com; robertgex@dwt.com; Law CPUC Cases; Barry, Donna L; nprocos@alamedapt.com; keithwhite@earthlink.net; robert.boyd@ps.ge.com; Michael.Whatley@SCE.com; Patrick McGuire (Patrick McGuire); dietrichlaw@earthlink.net; ramonag@ebmud.com; ceyap@earthlink.net; mrw@mrwassoc.com; bepstein@fablaw.com; dweisz@cera.com; dsh@cpuc.ca.gov; Cathy.Karlstad@SCE.com; rschmidt@bartlewells.com; rhwiser@lbl.gov; derek@denniston.com; richard.davis@SCE.com; brbarkovich@earthlink.net; james.read@brattle.com; rmccann@umich.edu; vwood@smud.org; cmkehrein@ems-ca.com; e-recipient@caiso.com; e-recipient@caiso.com; grosenblum@caiso.com; lpark@navigantconsulting.com; vfleming@navigantconsulting.com; karly.mccrory@rweschottsolar.us; dougdpucmail@yahoo.com; kevin@solardevelop.com; mclaughlin@braunlegal.com; dkk@eslawfirm.com; kdw@woodruff-expert-services.com; wwwesterfield@stoel.com; rroth@smud.org; karen@klindh.com; dws@r-c-s-inc.com; LAdocket@cpuc.ca.gov; as2@cpuc.ca.gov; ajo@cpuc.ca.gov; aes@cpuc.ca.gov; dil@cpuc.ca.gov; dsh@cpuc.ca.gov; jf2@cpuc.ca.gov; ltr@cpuc.ca.gov; lp1@cpuc.ca.gov; mrl@cpuc.ca.gov; nao@cpuc.ca.gov; psd@cpuc.ca.gov; pva@cpuc.ca.gov; pha@cpuc.ca.gov; sed@cpuc.ca.gov; rmiller@energy.state.ca.us; skorosec@energy.state.ca.us; JMcMahon@navigantconsulting.com;

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Subject: 2005 MPR: Aug 15th Conference pursuant to Rule 51.1 (b) -- Summary of Agreement / Invitation to Join Stipulation

RPS participants,

On August 15, 2005, PG&E convened a meeting to encourage the parties to agree on the gas price methodology to be used in establishing the 2005 market price referent (MPR). As outlined in the meeting announcement and in the PowerPoint presentation circulated to the parties before the meeting, the objective was to reach agreement on the following:

1) Guiding Principles outlined in the ALJ's July 7th Ruling and

2) Implementation details of the short-term (i.e., Years 1 through 6) gas price methodology to use in the MPR proxy.

The methodology for establishing gas prices for the remainder of the MPR period (Years 7-20) was not addressed.

Based on the workshop results, PG&E hopes that participants will agree to stipulate to matters contained in Tables 1 and 2 found below, so that a record of the parties' agreement can be presented to the Commission pursuant to Rule 51 of the Commission's Rules of Practice and Procedure.

Table 1 – Agreements Reached on the General Principles to be Used in Formulating the 2005 MPR Natural Gas Price Forecast:

As originally proposed in the July 7, 2005 ALJ Ruling following June 2005 MPR Workshops As agreed to by participating Parties in August 15, 2005 Rule 51.1 Conference

1. Reflects behavior of market participants. 1. Same as original.
2. Market data should be used to the extent possible. 2. Same as original.
3. For longer term contracts that extend beyond available market data, forecasts should exhibit a clear relationship to fundamental costs.
3. modified as follows: "For shorter-term contracts, forecast data should be verified against forward market data; for longer-term contracts that extend beyond available market data, forecasts should be benchmarked against fundamental costs and/or historical market data."
4. Methodology should be consistent with evaluation of other products. 4. Same as original.
5. Methodology should be verifiable using historical data. 5. combined with #3 above.
6. Methodology should be consistent with previous regulatory decisions. 6. Same as original.

Table 2 -- Agreement Reached with Participating Parties on the Sources and Methodologies to Shape the 1 to 6 year Short Term Period.

Issue 2004 MPR Methodology Proposed 2005 MPR Methodology

Surcharges (e.g., generator gas transmission fee, franchise fee, shrinkage) Gas prices should be estimated at the proxy power plant burner tip (per CPUC Staff Report on 2004 MPR, February 10, 2005, page 6) Same as 2004.

Hedging costs—gas (originally, transaction costs to hedge expected spot price forecast prices, now just transaction costs) $0.082/MMBtu,

consisting of one-half the bid/ask spread and a collateral carrying cost ($0.071 + $0.011, respectively) (per D.04-06-015, page 27) Same as 2004.
Basis (location differential)

- 50% SoCal Border plus generator transport
- 50% PG&E Citygate plus generator transport NYMEX ClearPort

(~2 years), then extend last year of actual basis quotes as a constant for remaining years. Two data sources for market basis quotes—NYMEX Clearport, and EnergyCurves/LIM. To the extent that market basis quotes do not cover the full 6 years, extend basis quotes as in E3's methodology adopted in D.04-05-024, Phase 1 Avoided Cost proceeding. [Note, subsequent to meeting, SDG&E and Crossborder expressed disagreement with the assumption of the basis equal to zero.]
Data Sources of Commodity Price NYMEX Henry Hub futures Same as 2004.

Time Length / Tenor Minimum 5 years of NYMEX Henry Hub futures, with CPUC staff discretion on the sixth year. Same as 2004.

Averaging Period and Calculation Start Date 60-trading-day averaging period, ending with bid due date of PG&E, calculated once for all IOUs. 22-trading-day averaging period, ending with short-list date of the last IOU to report, calculated for all 3 IOUs

Attached is a ***revised*** summary of agreement from the August 15th Meeting held at PG&E and via conference call on Short-Term Gas Price Methodology and Guiding Principles for the 2005 MPR. [A prior summary had been circulated to meeting participants on August 19th, and this document reflects participant feedback].

Each party may review the revised summary of agreement shown in Tables 1 and 2, and notify PG&E by **Tuesday, August 30**, if it wishes to join in a stipulation under rule 51.1 to propose to the ALJ.

Considering the concern raised by SDG&E and Crossborder subsequent to the meeting over the proposed basis adjustment, please indicate if you support 1) continuing the 2004 methodology (i.e. extending last basis quote); 2) using the E3 Methodology some other alternative for the basis adjustment.

PG&E proposes a follow-up conference call for **<u>Wednesday, August 31 at 9:00 A.M. PST</u>** to coordinate the submission of a joint party Stipulation pursuant to Rule 51.1 by September 2.

Conf call number: 1-877-241-3594
Participant Code: 305947

If interested in joining in the conference call or this stipulation, please contact Katherine Ryzhaya, <karp@pge.com> 415-972-5011 or Marc Kolb <mekd@pge.com>, 415-973-0206 by **<u>Tuesday, August 30.</u>**

Marc Kolb
Energy Revenue Requirements
PG&E
415-973-0206
<<Revised Summary of Agreement at 8-15 conference.doc>>

(END OF APPENDIX A)

APPENDIX B
RPS SOLICITATION TIMELINE
Updated from D.04-07-029

- Utilities file annual RPS procurement plans and RFOs.

- CPUC approves procurement plans and RFOs.

- Utilities issue RFOs.

- Respondents file notice of intent to bid.

- Deadline for respondents to submit bids.

- Utilities notify CPUC when bidding has closed.[1]
  Notification by letter to Executive Director.

- MPR is calculated by Commission when last solicitation is complete.
  CPUC staff calculates and discloses draft MPR in a draft resolution. After party comments, MPR is finalized when Commission adopts MPR resolution.

- Utilities evaluate the bids to develop short lists.[2]
  PRG meetings are held to review bid results.

- Utilities issue short-listed bids to CPUC and PRGs.
  Bidders have five days to withdraw all conflicting bids. Otherwise bid is binding.

- PRGs and CPUC review utilities' short lists.

- Utilities and bidders negotiate and execute contracts.

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[1] CPUC staff are not allowed to see the results of the RPS solicitations until the MPR is calculated and released in a draft resolution.

[2] Utility evaluation process may begin prior to MPR release and adoption.

- Utilities submit contract advice letters for CPUC approval.
  It may be appropriate for utilities to file contracts in groups as final agreements are reached. Contracts that do not require SEP funds could be submitted separately.

- CPUC reviews advice letters submitting contracts.

- Contracts are approved by adoption of Commission resolution.

- Sellers confirm PGC funding with utilities within 10 days after receiving notice of SEP determination from Energy Commission.
  After SEP determination is made, generators and utilities may re-structure payment streams in their contract or take other actions in accordance with Standard Terms and Conditions, "SEP Awards, Contingencies," based on SEP determination.

  If SEP award is not made within 120 days of submission of the contract for CPUC approval, generators may exercise termination rights under the provisions of Standard Terms and Conditions, "SEP Awards, Contingencies."

- If necessary, utilities submit amended advice letters with revised proposed contracts, reflecting results of SEP determinations, to CPUC for review and approval by resolution.

NOTE ON SEPs
Contracts approved by CPUC and having a contract price greater than the MPR may be eligible for SEPs. The Energy Commission's instructions for submitting applications and supporting materials are set forth in the current *New Renewable Facilities Program Guidebook*, available at http://www.energy.ca.gov/renewables/documents/index.html. 30 days after receiving a contract and all relevant data required to conduct the SEP evaluation, the Energy Commission releases PGC Funding Confirmations to CPUC, utility, and individual bidder and will identify any caps imposed. Final SEP awards are subject to conditions identified in the current *New Renewable Facilities Program Guidebook*.

(END OF APPENDIX B)