Decision **DRAFT DECISION OF ALJ ALLEN** **(Mailed 5/17/2004)**

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)

OPINION ADOPTING MARKET PRICE REFERENT METHODOLOGY

I. Summary

California Senate Bill (SB) 1078[1] established the California Renewables Portfolio Standard (RPS) Program, as generally set forth in Pub. Util. Code §§ 399.11-399.16.[2] The RPS Program requires each electrical corporation to procure at least 20% of its total retail electricity sales from eligible renewable energy resources by 2017. This target date was subsequently revised by the Energy Action Plan to 2010, in order to realize the benefits of renewable power more quickly.[3] Pub. Util. Code § 399.15(c) requires the Commission to adopt a Market Price Referent (MPR) methodology to estimate the long-term market

[1] SB 1078 from the 2001-2002 Legislative session, www.leginfo.ca.gov/cgi-bin/postquery?bill_number=sb_1078&sess=PREV&house=B&author=sher.

[2] An act to add Sections 387, 390.1, and 399.25 to, and to add Article 16 (Sections 399.11 - 399.16) to Chapter 2.3 of Part 1 of Division 1 of, the Public Utilities Code, relating to renewable energy.

[3] http://www.cpuc.ca.gov/static/industry/electric/energy+action+plan/index.htm.

price of electricity for use in evaluating bid products received during RPS power solicitations. In addition, we must adopt an associated MPR disclosure process, as required by Pub. Util. Code § 399.14(a)(2)(A), regarding how and when actual MPRs will be made public.

MPRs will establish a benchmark at or below which approved contracts will be considered *per se* reasonable, and above which contracts are eligible to receive Supplemental Energy Payments (SEPs), to be subsequently determined by the California Energy Commission (CEC). In today's order we (1) adopt a cash-flow simulation methodology to calculate MPRs, and (2) determine that MPRs will be publicly disclosed to all parties simultaneously, after utilities' power solicitations have closed and negotiations are complete, but before advice letters requesting contract approval are filed.

II. Background

Decision (D.) 02-10-062 directed all interested parties to file a proposed procedural process and schedule to implement SB 1078 on January 6, 2003, with reply comments on January 13, 2003. (*Id*., Ordering Paragraph (OP) 6.) On April 1, 2003, parties filed testimony in R.01-10-024 on issues associated with the implementation of the RPS program, including a process for determining MPRs. A majority of the parties addressed MPR issues in these filings, as noted in Appendices A & B of the staff MPR white paper "Discussion on Market Price Referents -- MPR Methodologies to Determine The Long-Term Market Price of Electricity for Use in California Renewables Portfolio Standard (RPS) Power

Solicitations,"[4] but no party clearly set forth either a distinct, stand-alone MPR methodology or an associated MPR disclosure process.

On June 19, 2003, the Commission issued D.03-06-071, an Order Initiating Implementation of the Senate Bill 1078 Renewable Portfolio Standard Program. D.03-06-071 provided guidance on a range of RPS issues, including development of an MPR methodology. Among other things, D.03-06-071 concluded that absent a sufficient number of existing, reasonably-priced, long-term power contracts of recent vintage currently in the utilities' respective resource portfolios, a combined cycle (CC) plant would serve as the proxy plant for establishing the referent price for the baseload power product, and a combustion turbine (CT) would serve as the proxy plant for establishing the referent price for the peaking power product. (*Id.*, OP 6.)

On March 22, 2004, Collaborative Staff issued the above-mentioned MPR white paper.[5] The MPR white paper proposed a specific proxy power plant methodology, based upon an Electric Power Resource Institute Technical Assessment Guide (EPRI/TAG) methodology, to calculate actual MPRs for baseload and peaking power products.

The purpose of the MPR white paper was to focus the discussion in preparation for workshops. The MPR white paper directed parties to file pre-workshop comments by Monday, April 5, 2004, and further stated that these

---

[4] MPR webpage: www.cpuc.ca.gov/static/industry/electric/renewableenergy/mpr.htm.

[5] The MPR white paper was prepared by the Commission's Energy Division and Division of Strategic Planning, in collaboration with the Renewable Energy Program of the California Energy Commission. We take official notice of the white paper, and incorporate it be reference into the record of this proceeding.

comments may become part of the record in the future. A number of parties requested an extension of time to April 9, 2004 to file pre-workshop comments. Energy Division granted this request via email on April 1, 2004.

Fourteen parties produced twelve sets of pre-workshop comments. On April 9, 2004, in response to the MPR white paper, six parties informally circulated pre-workshop comments via email to the R.01-10-024 service list: Cogeneration Association of California (CAC), the Center for Energy Efficiency and Renewable Technologies (CEERT), Solargenix Energy LLC (Solargenix),[6] Solel, Inc. (Solel), and The Utility Reform Network/San Diego Gas & Electric Company (TURN/SDG&E) jointly. Also on that date, seven parties formally filed pre-workshop comments in R.01-10-024: the California Wind Energy Association/the California Biomass Energy Alliance (CalWEA/CBEA) jointly, the Green Power Institute (GPI), the Independent Energy Producers Association (IEP), the Commission's Office of Ratepayer Advocates (ORA), Pacific Gas and Electric Company (PG&E), and Southern California Edison Company (SCE). On April 12, 2004, CLECA formally filed pre-workshop comments in R.01-10-024.

The Energy Division held workshops in San Francisco on April 15 & 20, 2004.[7] Several parties informally circulated post-workshop comments on April 23, 2004.

On April 30, 2004, ten parties filed nine sets of formal comments: CalWEA/CBEA (jointly), CEERT, GPI, ORA, PG&E, SCE, Solargenix, SDG&E, and TURN.[8]

---

[6] Solargenix was formerly known as Duke Solar.

[7] Workshop meeting agendas and list of attendees are available on the Commission's MPR webpage.

III. Discussion

Pub. Util. Code § 399.15(c) requires the Commission to adopt an MPR methodology to estimate the long-term market price of electricity for use in evaluating bid products received during RPS power solicitations. In addition, we must adopt an associated MPR disclosure process, as required by Pub. Util. Code § 399.14(a)(2)(A), regarding how and when actual MPRs will be made public.

The April 30, 2004 comments show general consensus on certain broader issues, although some of the details remain ambiguous or in dispute. For purposes of discussion, MPR issues can be categorized as process-related, modeling-related, or gas forecasting-related.

With regard to process, the Commission must specify how and when the MPRs will be disclosed. CEERT, PG&E, SCE, SDG&E, TURN, and CalWEA/CBEA provided recommendations on some or all of these issues.

With regard to modeling, eight of the ten commenting parties (CalWEA/CBEA, CEERT, GPI, PG&E, SCE, SDG&E, and TURN) agree that a cash flow modeling approach should be used to calculate the baseload and peaking MPRs. Six of these eight parties agree on using the SCE cash flow model as recommended by the MPR workshop Modeling Subgroup, whereas CalWEA and CBEA recommend using the TURN model.

With regard to gas forecasting, CalWEA, CEERT, PG&E, SDG&E, and TURN generally agree that some combination of New York Mercantile Exchange (NYMEX) data and forecasts of natural gas fundamentals should be utilized.

---

[8] All citations for parties' positions are to their April 30, 2004 filings, unless otherwise noted.

SCE, however, proposed using a "cost of carry" methodology in place of fundamentals-based forecasts. CalWEA, PG&E, SDG&E, and TURN agree on PG&E's hedging cost proposal, although CalWEA would apply the hedging costs to all twenty years whereas the other three parties would only apply it to the non-NYMEX years.

A. Defining the MPR

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" (OP 6). The decision also determined that the "market price referent will be calculated as an all-in cost, with an exception for as-available capacity" (OP 10). Eight of the ten commenting parties (CalWEA / CBEA, CEERT, GPI, PG&E, SCE, SDG&E, and TURN) agree that a cash flow modeling approach should be used to calculate the baseload and peaking MPRs. These same parties also agree that the MPR represents the levelized price associated with the appropriate referent generation technology, as described here. Each separate MPR represents the levelized price at which the proxy power plant revenues exactly equal the expected proxy power plant costs on a net-present value (NPV) basis.[9] For example, in the SCE model, the fixed and variable components of the MPR are calculated separately and summed to produce an all-in MPR price that reflects the proxy plant NPV on a levelized basis.

---

[9] The cash flow analysis assumes the proxy power plant will have a residual value of zero at the end of the 20-year term, which is a consensus assumption among the parties. While there will likely be some positive residual value at the end of the 20-year period, it would be difficult to estimate or agree upon.

With the cash flow model, the fixed component of the MPR is calculated iteratively (using the MS-Excel goal seek function), such that the expected revenues from the fixed component of the MPR exactly equal the expected fixed costs on a net-present value (NPV) basis. The total revenues from the fixed component are equal to the total annual production of the proxy power plant (e.g., 8 million kWh) times the fixed component of the MPR (e.g., 1.08 cents/kWh). These fixed component revenues will offset all fixed costs including Insurance, Property Taxes, Fixed O&M, Debt Cost (the cost of paying off the loan on the power plant), Income Taxes, and the cost of a Rate of Return on the down payment made on the power plant (the equity investment).

The variable component of the MPR is also calculated iteratively (using the MS-Excel goal seek function), such that the expected revenues from the variable component of the MPR exactly equal the expected variable costs on an NPV basis. The total revenues from the variable component of the MPR are equal to the total annual production of the proxy power plant (e.g., 8 million kWh) times the variable component of the MPR (e.g., 4.29 cents/kWh). These variable component revenues will offset all variable costs, including Variable O&M, the Cost of the Natural Gas to fuel the plant, and the cost of a Rate of Return on Operating Income (Variable Component Revenues less Variable Component Costs).

1. Six All-In MPRs Must Be Calculated

Section 399.14(a)(4) states that utility procurement plans shall include "direction to respondent bidders to offer prices for 10-, 15-, and 20-year contract terms." D.03-06-071 also stated "utilities should seek bids for 10, 15, and 20-year products" (p. 57). Therefore, one MPR must be calculated for a baseload product and another MPR for a peaking product. These two MPRs must be adjusted for contract terms of 10, 15, and 20 years. Thus, six all-in MPRs must be calculated.

In the April 30, 2004 comments, seven of the ten commenting parties (CalWEA/CBEA, CEERT, GPI, SCE, SDG&E, and TURN) respectively agreed with this approach. Specifically, these seven parties agreed with workshop consensus recommendation to use a cash flow model to calculate three baseload and three peaking MPRs. While PG&E generally agrees with this approach, PG&E contends that utility specific MPRs should be calculated (p. 4). Thus, PG&E would have us calculate six MPRs for each utility. In addition to the fact that we do not have a sufficient record from which to prepare utility-specific MPRs, PG&E's proposal is inconsistent with D.03-06-071, which stated that we would generally use statewide numbers. (*Id*., p. 21.)

Finally, we need to address the possibility that not all bidders may be able to submit bids that conform to the 10-, 15-, or 20-year contract term. A bidder may, for example, submit a 12-year contract bid. The MPR methodology, and associated model, set forth in this decision can be modified to calculate MPRs for different contract terms. If additional MPRs are required for bid evaluation, we authorize Energy Division to generate the necessary MPRs utilizing the same input values used to generate the 10-, 15-, or 20-year MPRs approved by this Commission. Alternatively, we could calculate all intermediate MPRs between years 10 and 20. When the utilities notify the Commission that negotiations with RPS bidders are complete, they should also indicate if the calculation of MPRs for terms other than 10, 15 or 20 years is necessary.

Table 1 Six All-In, Levelized Market Price Referents (MPRs) Must Be Calculated			
Product Type	**10-year $/kWh**	**15-year $/kWh**	**20-year $/kWh**
Baseload MPR	To be determined (Tbd)	Tbd	Tbd
Peaking MPR	Tbd	Tbd	Tbd

2. Utilities are not Required to Pay More Than the MPR

Pub. Util. Code § 399.15(a)(1) states that "an electric corporation shall not be required to enter into long-term contracts with eligible renewable energy resources that exceed the market prices established pursuant to subdivision (c) of this section." Thus, the MPR for a given power product and contract term establishes a dividing-line above which the utility is not obligated to pay, but for which a bidder may apply to the CEC for Supplemental Energy Payment (SEP) funding. Although this is clearly understood, the utilities have inquired as to their flexibility in structuring actual contract payments in a way that might result in certain payments in certain time periods actually exceeding the MPR. For example, a utility may want lower prices in the earlier years and higher prices in later years, or the opposite. For example, would it be acceptable if the MPR were 5.5 cents / kWh and the contract price for years 1 - 10 is 3.0 cents / kWh and 6.5 cents / kWh in years 11-20?

As an initial matter, we note that the one purpose of the MPR is to establish a standard of *per se* reasonableness applicable to RPS contracts. Approved contracts at or below an MPR would receive this reasonableness designation, which may be a benefit to the utility. However, the language of § 399.15(a)(1) is clear that the utility may choose to propose RPS contracts at supra-MPR prices. The Commission would carefully consider the merits of such contracts, bearing in mind the state's aggressive goals for renewable energy development and the limited amount of SEP funds presently available. While these supra-MPR contracts would not be considered *per se* reasonable, we encourage the utilities to propose all renewable contracts that provide ratepayer and environmental benefit.

We note, however, that the least-cost imperative is essential, and the utilities should not pass over cost-effective resources as a result of this direction, but rather may consider themselves encouraged to propose renewable contracts in excess of their RPS targets.

We interpret the utilities' question in light of the *per se* reasonableness standard. In response, we reiterate here that each MPR represents the levelized price at which the proxy power plant revenues exactly equal the expected proxy power plant costs on an NPV basis at an assumed discount rate. Thus, if the NPV of an alternatively structured contract results in lower prices in certain years and higher prices in other years, relative to the MPR, the yardstick with which to judge the *per se* reasonableness of the proposal would be to compute the NPV of that bid at an appropriate discount rate. If the NPV of the bid is less than or equal to the MPR, it will be considered *per se* reasonable.

B. Modeling the MPR

1. MPR Modeling Issues

With regard to modeling, eight of the ten commenting parties (CalWEA/CBEA, CEERT, GPI, PG&E, SCE, SDG&E, and TURN) agree that a cash flow simulation modeling approach should be used to calculate the baseload and peaking MPRs, as opposed to the closed form method that was presented in the MPR white paper. Parties agree that the SCE model, the TURN/SDGE model, and the CEC's Comparative Cost of Generation model (and associated report[10]) are all generally acceptable implementations of a cash flow simulation analysis. However, six of these eight parties agree on using the SCE cash flow model as recommended by the MPR workshop Modeling Subgroup, whereas CalWEA/CBEA recommends using the TURN model. Parties agree that the SCE model has one of the most transparent structures, and it requires the fewest modifications. In addition, parties agree that the same methodology and model should be used to calculate both the baseload MPRs and the peaking MPRs.[11] We accept this recommendation, and adopt the use of the SCE MPR model.

---

[10] The CEC's 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 version of this report. Note that prior to the table of contents in the August 2003 version, there are three pages of errata to the earlier June 5, 2003 Final Staff Report of the same name. The August 2003 report was prepared in support of the CEC's *Integrated Energy Policy Report (IEPR) Subsidiary Volume: Electricity And Natural Gas Assessment Report*, see p.10 for citation, www.energy.ca.gov/2003_energypolicy/index.html.

[11] In practice, two identical copies of the SCE MPR model would be utilized, one to calculate the baseload MPRs, and another to calculate the peaking MPRs. The model

Footnote continued on next page

In its April 30, 2004 comments, SCE provides an overview of the SCE MPR model structure and function (pp. 4-5). The model has certain fixed and variable components; for example, federal and state depreciation schedules and federal and state tax rates are fixed components in the model. A description of the model and a list of the variable components are attached to this decision (see "Appendix A: Description of SCE MPR Model").

The SCE comments further state that "in order to avoid a plethora of input cost categories" in the SCE MPR model, the parties agreed that most cost components should be assigned within the following variables in order to prevent "duplication or omission." The model contains the following five cost categories (aside from Capital Cost): Fixed O&M, Variable O&M, Fuel Cost, Insurance, and Property Tax. See Appendix A for a list of costs included under each of these categories.

2. Capital Recovery Term

PG&E, SCE, SDG&E, and TURN recommend that the calculation of all MPRs should be based on a capital recovery period of at least 20 years, regardless of the actual contract term. On the other hand, CalWEA/CBEA and CEERT recommend that winning renewable bidders should be allowed to, for example, recover their entire capital cost over a 10- or 15-year contract, even though a renewable power plant may have a useful life of 20 years or more. This issue represents a significant policy determination that will ultimately affect the actual value of the resulting MPRs, but one that is relatively easy to implement

---

structure and function would be identical between the two differing only by input values.

from a modeling standpoint. The key consideration here is the residual value of the proxy plant.

PG&E and SCE contend that it is more appropriate to assume a 20-year useful life for a proxy power plant (with a residual value of zero after 20 years).[12] TURN / SDG&E support this approach as well.[13] The bidder benefits from this approach in that there will very likely be a positive residual value after 20 years.[14]

In contrast, CEERT contends that that capital recovery should occur over the contract term, even if it is only 10 or 15 years. CalWEA / CBEA take a similar position. CEERT argues that (1) the average maturity of project loans is generally less than the length of the contract, (2) if the contract term is less than the project life (e.g., a 10-year contract), the owner is taking on the risk that revenues during years 11 to 20 will be sufficient to achieve the target equity return, and (3) this increased risk necessitates a higher target return in order to attract investment in the project.

CEERT's arguments are not persuasive, and it provides no real supporting evidence for its contentions. Potentially, a guaranteed capital recovery over 10 years might serve to increase risk. If this approach were adopted, it could conceivably lead to a disproportionate number of 10-year bids, which would be inconsistent with our goal of a more balanced and diversified

[12] Twenty-year capital recovery: PG&E April 30, 2004 Comments, p. 10; and SCE Pre-Workshop MPR Comments, April 9, 2004, p. 6.

[13] TURN / SDG&E Joint Comments on April 9, 2004, p. 7, attached to TURN's April 30 filing.

[14] We observe that many Qualifying Facilities (QFs) have recently opted for contract extensions at the end of their 20-year contracts.

power contract portfolio. Further, CEERT does not address the central issue of residual value, which was raised in pre-workshop comments. There is no good reason to believe bidders should assume a residual value of zero at the expiration of a contract shorter than 20 years. Therefore, for modeling purposes, we conclude that capital recovery should occur over 20 years, regardless of the contract term.

3. Capital Structure

The question of how a proxy power plant should be financed is an open issue. From a modeling standpoint, a key question is what ratio of debt to equity (capital structure) should be used, i.e., how much of the total capital cost of the project should be financed and how much should be paid upfront in the form of a down payment (equity in the project).

The parties present widely disparate numbers, in large part because the have cast this issue in terms of whether the proxy plant should be modeled as typical utility-owned asset or as an independent power producer. For example, CalWEA/CBEA note that the debt/equity ratio for PG&E and SCE is 52/48, while SDG&E is 51/49 (p. 9). CalWEA/CBEA suggests that the Commission might want to consider using an average of these numbers and the CEC Cost of Generation model, which assumes a ratio of 61/39 (resulting in something like a ratio of 56/34). CEERT essentially argues for the utility asset approach when it contends that the debt percentage should be less than what is used in the CEC Cost of Generation model. The TURN model (submitted with the April 9, 2004 TURN/SDG&E Pre-Workshop Comments) uses a 70/30 ratio. PG&E recommends a 55/45 ratio, whereas SCE proposes an 80/20 ratio of debt to equity. Parties did not, however, generally provide an abundance of supporting evidence or rationale for these recommendations.

Our goal is to construct an estimate of the long-term market price of electricity, and in this case that is through the use of a cash flow simulation analysis of a proxy power plant. A relevant question on this issue is, if such plant were constructed under current market conditions, how much leverage would be appropriate for a power plant?

We believe that the CEC model provides the most reasonable (and non-partisan) starting point. The CEC model uses an independent power producer, and given the current state of the market, that appears to be a more reasonable assumption than a utility-owned facility. Given the general context we are working in (and also consistent with our determination in the previous section), we will assume that the plant has a 20-year contract with a creditworthy utility.

It would not be appropriate to use a ratio less than that used in the CEC Cost of Generation Report, given that the report was "intended to provide a basic understanding [of] some of the fundamental attributes that are generally considered when evaluating the cost of building and operating different electricity generation technology resources" (p. 1).[15] Furthermore, the CEC Cost of Generation Report states: "debt financing costs were based on the expected terms for a merchant-financed project with a 12-year loan and a BBB debt rating in November 2001." (*Id.*, p. 9.) Under current market conditions, a proxy power

[15] These costs do not reflect the total costs to consumers of adding these technologies to a resource portfolio. The technology costs in this report are not site specific. If a developer builds a specific power plant at a specific location, the cost of siting that plant at that specific location must be considered. Some projects may require radial transmission additions, fuel delivery, system upgrades or environmental mitigation expenses. (CEC Cost of Generation Report, August 2003, p. 1.)

plant having a 20-year contract with a creditworthy utility would be able to utilize more leverage and thus attain a higher debt/equity ratio. From the record before us, the model that appears to most closely correspond to these realities is the TURN proposal. Accordingly, we will use a 70/30 debt/equity ratio for MPR modeling purposes.

4. Selection of Modeling Inputs

As previously discussed, there is general consensus among the parties on the appropriate categorization and classification of cost inputs necessary to run a cash flow simulation of a proxy power plant over a 20-year period. However, there is not broad consensus on (1) general decision criteria upon which to select actual input values, or (2) acceptable data sources for these values.

There is a spectrum of opinion regarding the most appropriate general decision criteria to use in selecting actual input values. On one end, CalWEA/CBEA contends that the Commission should adopt capital cost assumptions that are "broadly representative of plants actually being developed and built in California" (p. 7). At the other end, SCE argues that: "input assumptions should be selected so as to produce the lowest reasonable MPR to best reflect the values that would result from a utility solicitation" (p. 8). PG&E states that: "input values should be reliable and unbiased" (p. 4).

With regard to acceptable data sources for input values, PG&E recommends the use of "bond financing prospectuses, property tax records, and mandatory filings with regulatory agencies such as the Securities and Exchange Commission" (p. 4). In addition, "PG&E supports the CPUC retaining an independent third-party consultant such as an investment bank to survey the market and compile capital and operating cost input assumptions from such sources of information."[16] SCE recommended that the Commission "look to experts in the capital finance and project development field, who can provide current market data, understand current market trends and can knowledgeably extrapolate beyond current data," at the time the MPRs are calculated. SCE suggests, with respect to technology-specific data (O&M costs and heat rate) that the Commission obtain empirical data from major Original Equipment Manufacturer (OEMs) like General Electric Company (GE) and Siemens (pp. 7-8). In addition, most every party put forward recommended input values or ranges.

On the issue of specific modeling inputs, we must carefully assess the recommendations put forward to ensure that these values and ranges are supported not only by judgment, but also grounded in evidence and supported by a clear rationale. Numbers put forward alone without significant basis will be weighed accordingly in our decision-making. Because we are only required to adopt a specific MPR methodology at this time, and because we must balance the tradeoffs between transparency and competitiveness, we will not rule on specific inputs at this time, aside from our determination set forth in the capital structure section of this decision.

However, with regard to general decision criteria with which to select actual input values, we determine here that it is appropriate for us to use a consistent set of input assumptions that would account for certain cost tradeoffs. For example, plants with higher capital costs may be expected to have lower heat

[16] PG&E further suggests that the "least emphasis or reliance should be placed on information from such sources as press releases, trade press articles, or other such self-published materials because there is no verification or fiduciary responsibility for the project proponent to provide a full and accurate accounting of project costs" (p. 4).

rates, and plants with higher variable O&M expenditures may have less heat rate degradation over time.

5. Peaker Proxy Plant

For purposes of the MPR, we define a peaker power plant as a Combustion Turbine (CT) generator with a relatively low capacity factor that delivers a majority of its power during on-peak, daylight hours. Parties generally agree that the same methodology and model should be used to calculate the baseload and peaking MPRs. In addition, the gas price forecast data should be the same for both the baseload and peaking MPRs.

Certain inputs to the peaking MPR model, however, will be different, such as the capacity factor, heat rate and capital cost appropriate for a CT facility. Bearing these distinctions regarding certain inputs in mind, we agree that the basic design of the MPR model should be the same, as should be the gas forecasts utilized for both calculations.

C. MPR Gas Forecasting Issues

Section 399.15(c)(1) requires the Commission to determine the "long-term market price of electricity for fixed price contracts" over certain terms. There is consensus among the parties that there is no transparent, liquid market for natural gas forward products for 10, 15 or 20-year terms, which is necessary in order to fuel a proxy power plant producing fixed-priced electricity over these time periods. For purposes of discussion, we will address a gas price methodology for years 1 through 6, and another methodology for years 7 through 20. We will, however, first specify the source and composition of these gas prices.

1. Forecast at the Proxy Power Plant Burnertip

CalWEA / CBEA, PG&E, SCE, TURN and SDG&E agree that the NYMEX data should be basis adjusted (positive or negative) to California, plus the SoCal / PG&E average distribution rate (with an appropriate escalation). CalWEA / CBEA and PG&E also recommend adding a statewide average franchise fee surcharge. No party supports adjustments for imbalance and storage costs, or the use of a separate peaking price based on observed differences in summer month prices, as considered during the workshops.

We agree that gas prices should be estimated at the proxy power plant burnertip. This would include a basis adjustment to the California border (e.g., the average of the SoCal border and the PG&E Citygate delivery points), along with charges for intrastate transportation, shrinkage (if applicable), distribution, municipal franchise fee, and any hedging costs that may be appropriate. In addition, the gas price forecast data should be the same for both the baseload and peaking MPRs.

2. Gas Forecasting -- Years 1 through 6

There is consensus among the parties that NYMEX futures contracts are the best representations of forward market prices for natural gas; however, there was not consensus on using NYMEX prices for the entire period of years 1 through 6. CalWEA / CBEA, PG&E, and SCE would use NYMEX prices for the entire period of years 1 through 6. CEERT would only use NYMEX prices for the first two years. TURN and SDG&E would only use NYMEX prices for the first three years, unless significant trading volumes justify reliance on prices for years

4 through 6. CEERT, TURN, and SDG&E all expressed concern that the contracts in years 4 through 6 are, in some cases, too lightly traded or not traded at all.[17]

Neither CEERT, TURN, nor SDG&E set forth an acceptable volumetric threshold above which the use of NYMEX prices would be considered sufficiently liquid to be acceptable for years 3 through 6. Because these are in fact available transaction-based prices for natural gas forwards, and because no quantitative threshold or other basis was adequately presented to judge these transactions as insufficiently liquid, we see no compelling reason not to use the full six years of available NYMEX futures prices. Therefore, for the purposes of forecasting gas prices in years 1 through 6, we will use the full six years of NYMEX data. We will monitor the results of this method and make any necessary adjustments to this approach in the future.

Regardless of whether we use NYMEX data for the first two, three, or six years, there remains a question as to the granularity of that data (i.e., whether we should use a daily, weekly, or monthly average of the NYMEX data). PG&E recommends using the most recent NYMEX 22-trading day average. TURN and SDG&E contend that a NYMEX 60-trading day average should be used. CEERT suggests, “a longer averaging period of perhaps six months should be used” (CEERT, p. 13). PG&E notes that a 22-trading day historical average of closing prices for each NYMEX contract will avoid the possibility of a short-term spike or dip in futures prices to skew a 10- or 20-year MPR price (PG&E, p. 22). While PG&E has a valid point, we believe that a longer time period would in fact be more useful in smoothing statistical anomalies in the forecast price.

[17] It is our understanding that for futures contracts that have not traded, NYMEX reports calculated prices rather than last trades as daily closing prices.

Therefore, for purposes of establishing the gas price forecast for years 1 through 6, we will use a NYMEX 60-trading day average.

3. Gas Forecasting -- Years 7 through 20

CalWEA/CBEA and PG&E recommend that the Commission use natural gas fundamentals forecasts produced by CERA, PIRA, and Global Insight[18] to forecast prices for years 7 through 20. In addition, CalWEA/CBEA noted that the public sector forecasts produced by the CEC and the Energy Information Administration (EIA) could also be consulted, but only in the event that those forecasts are no more than six months old. TURN recommends using an average of these private and public sector forecasts. SDG&E supports TURN's April 30, 2004 comments on gas pricing issues (SDG&E Comments, p. 4). CEERT generally recommends the same approach as TURN. In contrast, SCE contends that such natural gas fundamentals forecasts should not be used at all, and instead recommends the use of a cost of carry model to calculate expected gas prices for years 7 through 20, "as an alternative to using price forecasts as a surrogate for forward prices." (SCE Comments, April 30, 2004, p. 11.)

a) Fundamentals Forecasts

As already mentioned, CalWEA/CBEA and PG&E recommend that the Commission use specific natural gas fundamentals forecasts produced by CERA, PIRA, and Global Insight to forecast prices for years 7 through 20. However, CalWEA/CBEA also recommended that the Commission carefully

---

[18] Private sector natural gas forecasts by Cambridge Energy Research Associates (CERA), PIRA Energy Group, and Global Insight (formerly DRI), respectively.

consider the details and underlying assumptions embedded in these forecasts as follows:

> "CalWEA/CBEA urge the Commission to use judgement [sic] in the choice of which of the private forecasts to use. In addition to using only forecasts prepared in the last six months, the Commission should only use forecasts with an adequate number of data points for the forecast period. For example, in reviewing the exemplary forecast that PG&E presented in its April 9 comments, CalWEA/CBEA noted that the PIRA forecast appears to include just two data points in the 20-year forecast period. PG&E applied each of these data points as a constant price for a five-year period. CalWEA/CBEA submit that this is not enough data to use for a 20-year gas forecast. Furthermore, PG&E's forecast used only the relatively low EIA forecast for the final years of the forecast, because CERA and PIRA data did not extend to 2023. This caused PG&E's forecast to drop suddenly in the later years. The Commission should use an average of several forecasts only for the years that are covered by all of the forecasts. If one or more of the forecasts ends before the end of the forecast period, then the average value for the last year covered by all of the forecasts should be escalated to future years based on the escalation rates in the other forecasts. This will avoid discontinuities in the forecast caused simply by a lack of data from some forecasters." (CalWEA/CBEA April 30, 2004 Comments, p. 4.)

Alternatively, TURN recommends using a forecast of escalation rates, or the rate of change between time-series price data in the forecast. In practice, one would determine the average escalation rate of the private and the public sector forecasts, which could then be "applied to the last NYMEX price for the remaining years of the MPR to obtain a proxy 'fixed' price over the entire period." (TURN Comments, p. 6.) SDG&E concurs with TURN. CEERT also recommends the same approach as TURN, although CEERT would use year 2 NYMEX data as a base year to compute a forecast for years 3 through 20.

TURN notes that by using an average of the available forecasts of escalation rates, as applied to the last year of NYMEX data, the Commission would avoid the task of "attempting to reconcile discontinuities between forward prices and forecasts - an exercise certain to consume substantial resources without resulting in any appreciable increase in real-world accuracy." (TURN, p. 6.)

Regardless of whether we opt to use a specific fundamentals forecasts, an average of the forecasts, or just the average annual escalation rate of one or more fundamentals forecasts, our MPR process will, to a certain degree, be dependent upon these outside forecasts to calculate MPRs for use in RPS power solicitations. To date, we have not received information on the record regarding the frequency with which these public and private sector forecasts are published and whether the respective publication cycles would impose constraints on the MPR process. For example, we might be faced with the possibility of either calculating MPRs using slightly stale natural gas forecast data (older than six months), or waiting until updated forecasts have been published.

b) Cost of Carry Model

On the other hand, SCE contends that "the cost of carry model provides a consistent way to estimate long-term fixed gas prices," (p. 11) without using public or private sector fundamentals forecasts. However, SCE did not submit an actual cost of carry model for our review and consideration. According to SCE's comments, "the cost of carry model is standard in the economic theory of derivatives markets." Specifically, according to SCE, "the cost of carry model relates the forward price of a commodity to (1) the spot price, and (2) the risk-free interest rate, (3) the cost of physically storing the commodity, and (4) the convenience yield on the commodity."

SCE provided few details regarding this approach. As we generally understand the cost of carry model, it would essentially compute a single, annual escalation rate to be applied to a base year gas price, where the base year gas price might, for example, be a 12-month average of the year-6 NYMEX prices (e.g., March 2009 through March 2010). Two advantages of the cost of carry model approach are (1) it would be transparent, and (2) it would be easy to update at any time. In contrast, public and private sector fundamentals forecasts may not be published on a regular basis, and such forecasts are admittedly subjective, given that many underlying assumptions reflect significant judgment calls about uncertain future events.

Consequently, we are open to examining a specific cost of carry model as a forecasting approach if and when one becomes available. However, although this approach has some potential advantages, the fact remains that we have not been presented with a specific model, nor have we had the opportunity to fully consider whether an economic theory of derivative markets would accurately capture the complex and evolving dynamics specific to natural gas transactions in California. The cost of carry model is consequently not a viable forecasting tool for use at this time in this proceeding. Therefore, we will instead use a fundamentals forecast approach, and more specifically, the forecast of escalation rates method advocated by CEERT, TURN, and SDG&E, as described above.[19]

4. Discontinuity Adjustment Between the NYMEX Forward Curve and Fundamentals Forecasts

In the event we use actual price series data from one or more fundamentals forecasts, there will likely be a discontinuity between the NYMEX data and the fundamentals forecast data, specifically between years 6 and 7. The degree of such a discontinuity may warrant different types of adjustments in order to blend or merge the two data sets together. However, there would be no discontinuity effect in the event we opt to use the forecast of escalation rates approach advocated by CEERT, TURN, and SDG&E.

If the CEERT, TURN and SDG&E approach is not taken, there are at least two ways to address a discontinuity between the NYMEX forward curve (years 1 through 6) and the fundamentals forecasts (years 7 through 20). We have the option of (1) making no adjustment, or (2) blending the two data sets. At this time, we opt to use the forecast of escalation rates approach advocated by CEERT, TURN, and SDG&E, applied to year 6 of the NYMEX data, in order to calculate the gas price component of the MPR for specific contract lengths. Under this approach no discontinuity between the two data sets is created.

5. Calculation of Hedging Costs

Hedging costs as applied here refer to the additional expense incurred to guarantee the purchase price of natural gas. With regard to these

---

[19] The natural gas forecasts employed in this process will include the most recent or otherwise most appropriate forecast prepared by the CEC. (See, Public Resources Code section 25302.)

costs, CalWEA / CBEA, PG&E, TURN, and SDG&E support PG&E's proposed method of calculating a natural gas hedging cost premium. PG&E, TURN, and SDG&E would only apply this hedging cost premium to forecast years 7 through 20 (to the non-NYMEX gas prices), whereas CalWEA / CBEA supports applying a hedging cost premium to all 20 years. We conclude that, if a hedging cost premium is appropriate, it should only be applied to the non-NYMEX gas prices (e.g., years 7 through 20), because the NYMEX values represent a fixed price for the fuel that can be transacted in a transparent market. Imputing a further hedging cost to the price of these NYMEX transactions would therefore be redundant. In contrast, the forecast of gas prices for years 7-20 do not represent the full cost to lock in a gas price for the years in question. A hedging value is needed to establish this price certainty.

PG&E proposes to add one-half of the bid / ask spread as observed on the NYMEX floor for both natural gas futures and natural gas basis contracts, plus a collateral carrying cost (pp. 25-26 of PG&E post-workshop comments). PG&E states that their proposal is offered in lieu of the hedging value recommendations set forth by many of parties in their pre-workshop comments. PG&E notes that Ryan Wiser, a primary author of the Lawrence Berkeley National Laboratory study cited by a number of the parties (and who also participated in the MPR workshop), stated (as part of the MPR Gas Subgroup Report) that it was not appropriate nor was it his intention for parties to simply add the $0.45 to $0.80 / MMBtu derived in the study to any forecast as a "hedging value."

PG&E computes the hedging value as follows:

	Cost ($ / MMBtu)
Bid / Ask Spread	$0.071

Collateral (Letter of Credit Cost at 1.25%)	$0.011
Total Hedging Cost	$0.082

PG&E's hedging proposal would be reasonable were the Commission to choose to directly adopt the gas price forecasts as inputs to the MPR calculation. In that case, we would need to add a hedging premium to convert these forecasted prices into an estimated cost to "lock in" those prices into the future.

Under the approach we adopt here, however, we will utilize NYMEX data as inputs for the years 1 through 6. While we are sensitive to the fact that there may be minimal liquidity in this market, and we may need to revisit this determination in the future, nonetheless these are firm prices for natural gas, and we have determined that no hedging premium is appropriately added to the prices evident for these years.

Applying an average of the escalation factors present in the gas forecasts for years 7 through 20 to the final fixed-price year available from NYMEX has the effect of estimating a fixed price for gas for all the years of an RPS contract. Essentially, the gas price is hedged automatically by escalating a fixed price contract from year 6 of the NYMEX transactional data. Adding a hedging premium on top of this estimate would therefore be redundant, just as adding a hedging premium to the NYMEX data would be. Therefore, we will not adopt a separate hedging value for the gas forecasts for years 7 through 20, unless compelling evidence is subsequently presented that requires us to alter this determination. Escalating a fixed price contract does the job directly.

IV. Disclosing the MPR

SB 1078 set forth specific procedural requirements regarding how and when actual MPRs will be calculated and disclosed. Pub. Util. Code § 399.14(a)(2)(A) states:

> "A process for determining market prices pursuant to subdivision (c) of Section 399.15. The commission shall make specific determinations of market prices after the closing date of a competitive solicitation conducted by an electrical corporation for eligible renewable energy resources. In order to ensure that the market price established by the commission pursuant to subdivision (c) of Section 399.15 does not influence the amount of a bid submitted through the competitive solicitation in a manner that would increase the amount ratepayers are obligated to pay for renewable energy, and in order to ensure that the bid price does not influence the establishment of the market price, the electrical corporation shall not transmit or share the results of any competitive solicitation for eligible renewable energy resources until the commission has established market prices pursuant to subdivision (c) of Section 399.15."

Under these requirements, the Commission must calculate actual MPRs <u>after</u> the closing date of a competitive solicitation, but <u>before</u> the utilities transmit or share the results of any competitive solicitation with the Commission.

1. When Actual MPRs are Disclosed

In order to implement these requirements, the Commission must clearly define the term "closing date of a competitive solicitation." A strict interpretation of this closing date would clearly be the date and time at which all bids are due. A more pragmatic interpretation might allow for some negotiation time subsequent to the bid close date. CalWEA / CBEA, CEERT, SCE, SDG&E, and TURN have indicated that the utilities and the short-listed bidders should have some time to negotiate deals after bidding closes. In contrast, PG&E suggested that the Commission disclose MPRs the day after the bid close date.

The Commission must also specify exactly what it means for utilities to "transmit or share the results of any competitive solicitation with the Commission." During the second day of MPR workshops, parties discussed whether actual MPRs should be disclosed publicly to everyone at the same time, or if MPRs should be simultaneously disclosed only to the utilities, their short-listed bidders, and to their Procurement Review Groups (PRGs). In their April 30, 2004 comments, CalWEA/CBEA, CEERT, SCE, SDG&E, and TURN recommended that MPRs should be publicly disclosed to everyone at some point between (1) the close of bidding (allowing for some subsequent negotiation time) and (2) the filing of a utility advice letter requesting contract approval.

We interpret the "transmit or share" requirement to mean that the utilities cannot formally or informally (through applications, advice letters, or discussions with the PRG, etc.) disclose to or otherwise inform the Commission of the results of any competitive solicitation for eligible renewable energy resources prior to the Commission calculating actual MPRs.

Therefore, we conclude that the MPRs should be disclosed after bidding has closed and negotiations are complete, allowing for the possible collaboration between bidders in support of gen-tie costs (see, May 11, 2004 Proposed Decision in I.00-11-001, re transmission bid adder methodology), but before utilities file their requests for contract approval. In order to implement this approach, the utilities must notify the Commission via letter to the Executive Director that bidding and subsequent negotiations have concluded, and that the utilities are requesting that the Commission calculate and disclose actual MPRs as soon as possible.

2. How Actual MPRs are Calculated and Disclosed

Once the Commission adopts an MPR methodology, actual MPRs must be calculated at the appropriate time for each RPS solicitation, as described above. To provide clarity to all parties and to Energy Division staff, we outline the process for calculating and disclosing actual MPRs. After the closing date of a competitive solicitation, Energy Division staff shall be prepared to run a model capable of calculating actual MPRs that is compliant with the MPR methodology adopted in this decision. During the course of these calculations, staff shall not disclose draft calculations to the public, any outside parties, or to any of the utility PRGs. Energy Division staff may obtain any necessary input data from outside sources. In order to ensure the best available data, Energy Division staff may also, at its discretion, retain any necessary consulting services (as its budget may allow) to determine appropriate modeling input values. Energy Division staff shall not disclose its entire working data set to any outside consultant.

CEERT, SDG&E, and TURN recommend that MPRs be disclosed via ALJ Ruling. SCE recommends that the Commission issue a formal decision approving actual MPRs. PG&E does not define a precise vehicle and simply states that the "CPUC advises the procuring utility of the MPR."

In order to provide a timely response and allow the solicitation process to move forward, we order that actual MPRs will be disclosed by ALJ Ruling. Final approval of contracts, incorporating the underlying MPR, will be by Commission Decision.

V. Assignment of Proceeding

Michael R. Peevey is the Assigned Commissioner and Peter V. Allen and Julie Halligan are the assigned Administrative Law Judges in this proceeding.

VI. Comments on Draft Decision

Pursuant to Section 311(g)(2) of the Public Utilities Code, this decision must be served on all parties and subject to at least 30-day public review and comment prior to a vote of the Commission. Section 311(g)(2) provides that this 30-day period may be reduced or waived upon the stipulation of the parties in the proceeding.

At the PHC held on May 5, 2004, the parties stipulated to shorten the comment period. Accordingly, opening comments must be filed by May 28, 2004 and reply comments must be filed by June 4, 2004.

Findings of Fact

1. Pub. Util. Code §§ 399.14(a)(2)(A) and 399.15(c) require the Commission to adopt a process and methodology for establishing an MPR to be used in implementing the RPS program.
2. Commission D.03-06-071, as modified by D.03-12-065, began the implementation of determining a process and methodology for establishing an MPR.
3. Commission staff has issued a white paper and has held workshops and received comments on the subject of the MPR.
4. Different MPRs are needed for each contract term and power product.
5. Determining a methodology for establishing the MPR requires choosing a gas forecasting approach and a modeling approach.
6. NYMEX futures contracts are a source of forward market prices for natural gas.
7. Forecasts of forward market prices based on natural gas fundamentals are available from a number of sources.

8. A cash flow simulation model can be used to calculate baseload and peaking MPRs.

9. Calculation of MPRs requires a defined capital recovery term.

10. A capital recovery term of 20 years more closely matches reality than a shorter term.

11. Calculation of MPRs requires a defined capital structure.

12. The CEC model provides a capital structure that is a reasonable starting place for calculations.

13. The CEC model of capital structure does not exactly correspond to the facts in this proceeding.

14. Modeling inputs may be obtained from outside sources.

15. A combustion turbine is a reasonable proxy for a peaker plant for purposes of calculating an MPR.

16. Pursuant to Pub. Util. Code § 399.14(a)(2)(A), the MPR must be disclosed only after the closing date of a competitive solicitation.

17. The timing of the disclosure of the MPR is important.

18. An ALJ Ruling allows for more precise timing of the disclosure of the MPR.

Conclusions of Law

1. There is an adequate record in R.01-10-024 and in this proceeding to adopt an MPR methodology.

2. Six statewide MPRs should be calculated, corresponding to the three contract terms and two power products.

3. In determining an MPR methodology, it is reasonable to use NYMEX gas futures prices and forecasts based on natural gas fundamentals.

4. In determining an MPR methodology, it is reasonable to use a cash flow simulation model.

5. A capital recovery term of 20 years is reasonable to use for modeling purposes in calculating an MPR.

6. A 70/30 debt/equity ratio is reasonable to use for modeling purposes in calculating an MPR.

7. Commission staff should seek reliable outside sources for modeling inputs.

8. The same methodology and model should be used to calculate baseload and peaking MPRs.

9. Inputs for a peaking MPR model will be different from those for a baseload MPR model.

10. An ALJ Ruling is the preferable approach for the release of the MPR.

O R D E R

IT IS ORDERED that:

1. A Market Price Referent methodology is adopted, as described above, consistent with the preceding Findings of Fact and Conclusions of Law.

2. The Assigned Commissioner and Assigned Administrative Law Judge's will make such rulings as are necessary to effectuate this order.

3. This order is effective today.

Dated ____________________________, at San Francisco, California.