Decision 08-10-026 October 16, 2008

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

DECISION ON MARKET PRICE REFERENT FOR THE CALIFORNIA RENEWABLES PORTFOLIO STANDARD

TABLE OF CONTENTS

DECISION ON MARKET PRICE REFERENT FOR THE CALIFORNIA RENEWABLES PORTFOLIO STANDARD

1. Summary

This decision refines the methodology for the market price referent (MPR) for use in the California renewables portfolio standard (RPS) program in 2008 and later years. The MPR implements the Legislature's mandate that the Commission determine the market price of electricity in order to evaluate the reasonableness of prices of long-term power purchase agreement (PPAs) for RPS-eligible electric generation. This decision continues the use of a "proxy plant" for modeling the levelized price of a utility's long-term PPA with a new natural-gas fueled generation facility in California.

The decision addresses several aspects of the existing MPR methodology in order to improve the accuracy, transparency, and simplicity of the modeling for the MPR proxy plant. It adjusts the method for determining the cost of natural gas fuel for the proxy plant to include data from up to 12 years of forward natural gas contracts traded on the New York Mercantile Exchange and to provide a reasonable prediction of gas prices in the later years of the proxy plant's long-term forward gas contract. It refines the methodology for the capacity factor used for the combined cycle gas turbine proxy plant to increase consistency and transparency of the modeling by adopting a statewide technical capacity factor. The decision makes minor updates to the methodology for calculating installed capital costs for the proxy plant. It also ends the use of a factor for calculating transmission line losses.

The decision includes as a permanent feature of the MPR methodology the calculation of the cost of compliance with regulatory programs limiting greenhouse gas (GHG) emissions. It sets forth a method for determining the

GHG compliance cost for the MPR proxy plant that takes into account the rapid changes occurring in this regulatory area.

The decision also maintains the Commission's current practices of publicly disclosing the MPR calculation and of requiring the public disclosure of the information whether the price of an RPS procurement contract is at, below, or above the MPR.

Finally, the decision examines briefly several issues raised by Energy Division staff and the parties related to the MPR that do not require changes to the MPR methodology, but should be considered by staff in preparing the actual calculation of the MPR for 2008 and later years.

2. Procedural Background

The Commission set the initial parameters for the MPR in Decision (D.) 03-06-071. The method for calculating the MPR was first developed in D.04-06-015. In D.05-12-042, the methodology for calculating the MPR was expanded and stabilized. This methodology has been used for the resolutions implementing the MPR for 2005 (Resolution (Res.) E-3980 (April 13, 2006)) and 2006 (Res. E-4049 (December 14, 2006)). For 2007, in D.07-09-024, the Commission adopted an interim method to account for the costs of the emission of greenhouse gases (GHG adder). The 2007 MPR was implemented in Res. E-4118 (October 4, 2007).[1]

D.07-09-024 authorized the use of the GHG adder for the 2007 MPR only. That decision also authorized an examination of the MPR for 2008 and later

---

[1] The MPR model for 2007 may be found at http://www.cpuc.ca.gov/PUC/energy/electric/RenewableEnergy/mpr.

years, to determine whether any changes should be made to the MPR methodology, including how the costs of regulation of GHG emissions should be reflected in the MPR in 2008 and later years.

The 2008 review process began with the comments filed March 6, 2008 in response to the Administrative Law Judge's (ALJ's) Ruling Requesting Pre-Workshop Comments on 2008 Market Price Referent for the Renewables Portfolio Standard Program (February 8, 2008) (pre-workshop ruling).[2] On March 27, 2008, Energy Division staff held a workshop where parties discussed potential modifications to the MPR methodology, inputs, and assumptions for 2008 and later years. Post-workshop comments were requested by the ALJ's Ruling Requesting Post-Workshop Comments on 2008 Market Price Referent for the Renewables Portfolio Standard Program (May 20, 2008) (post-workshop ruling) and were filed on June 6, 2008.[3] Reply comments were filed on June 18, 2008.[4]

---

[2] Pre-workshop comments were filed by California Wind Energy Association (CalWEA), California Cogeneration Council, and the Concentrated Solar Power Companies, jointly; Center for Energy Efficiency and Renewable Technologies (CEERT); Central California Power (CCP); Energy Producers and Users Coalition (EPUC) and Cogeneration Association of California, jointly (collectively, EPUC); Green Power Institute (GPI); GreenVolts, Cleantech America, and Community Environmental Council, jointly; Pacific Gas and Electric Company (PG&E); San Diego Gas & Electric Company (SDG&E); Solar Alliance and California Solar Energy Industries Association, jointly (collectively, Solar Alliance); Southern California Edison Company (SCE); The Utility Reform Network (TURN); and Union of Concerned Scientists (UCS).

[3] Post-workshop comments were filed by CalWEA, California Cogeneration Council, Large-scale Solar Association, and Solar Alliance, jointly (collectively, CalWEA); CCP; Division of Ratepayer Advocates (DRA); EPUC; GPI; PG&E; SDG&E; Shell Energy North America (US), L.P (Shell).; SCE; TURN; and UCS.

[4] Post-workshop reply comments were filed by CalWEA; CEERT; CCP; GPI; PG&E; SCE; TURN; and UCS.

The ALJ's pre-workshop ruling noted that "[a]fter considering the information developed in the workshop and all comments and reply comments, the Commission may modify any of its prior MPR decisions, or issue a new decision on the MPR, or it may conclude that no changes warranting a decision are needed." This decision effectuates the second option, issuing a new decision that incorporates all revisions to the MPR methodology necessary for 2008 and later years, subject to any new developments that may warrant further changes.

3. Discussion

3.1. History

The RPS program was initiated by Senate Bill (SB) 1078 (Sher), Stats. 2002, ch. 516.[5] To establish the market price necessary for implementing RPS procurement by investor-owned utilities (IOUs), the legislation requires this Commission, in consultation with the California Energy Commission (CEC), 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.

---

[5] RPS legislation is codified at Pub. Util. Code §§ 399.11-399.20. All further references to sections refer to the Public Utilities Code unless otherwise specified.

(3) The value of different products, including baseload, peaking, and as-available output. (§ 399.15(c).)

If a contract price (on a net present value basis) exceeds the MPR, it may trigger consideration of methods to fund the above-market costs of long-term contracts for RPS-eligible generation entered by IOUs and approved by the Commission.[6]

In D.03-06-071, the Commission decided to rely on the second and third considerations set out in § 399.15(c). D.04-06-015 adopted 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." D.05-12-042 refined and stabilized the MPR model.

The MPR model, as set out in D.05-12-042 and applied for the past several years, requires several types of input data, including natural gas prices, capital costs, operating costs, finance costs, taxes, and power delivery assumptions. In D.07-09-024, the Commission made a temporary change to the MPR methodology to include a GHG adder for 2007 only.

3.2. Gas Costs

3.2.1. Long-Term Gas Forecast

The most significant cost during the life a new combined cycle gas turbine (CCGT) is the cost of its natural gas fuel. The MPR models the cost of gas over

---

6 The original method for funding above-market costs was the use of Supplemental Energy Payments (SEPs), administered by the CEC. See §§ 399.13(c), 399.15(b)(5). The SEP program was eliminated by SB 1036 (Perata), Stats. 2007, ch. 685. The existing funds were refunded to the three large IOUs (PG&E, SDG&E, and SCE) and, along with the portion of funds which would have been collected through January 1, 2012, will be used to fund above-market costs of their long-term RPS contracts. *See* Res. E-4160 (April 10, 2008).

the entire life of the proxy plant's long-term contract.[7] As the Commission pointed out in D.05-12-042, no new gas-fired plant in California actually enters into a 20-year fixed price contract for physical gas delivery. In order to capture the "fixed-price fuel costs associated with fixed-price electricity from new generating facilities,"[8] the MPR model creates a forecast of long-term gas prices for purposes of the MPR. As explained in D.05-12-042, this model is based on the fact that participants in the California market for PPAs[9] "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." (D.05-12-042, p. 17.)

Several parties argue that the current MPR gas forecast methodology does not provide accurate enough projections of gas costs. No party disputes the graphical representations of the divergence between gas forecasts and gas prices over the last decade presented by CEERT in its post-workshop reply comments. The parties propose varying solutions, in the context of the MPR methodology, to this widely acknowledged but poorly understood tendency of fundamental

---

7 This is one of the significant differences between the MPR methodology and the method for determining the short-run avoided cost (SRAC) that is the basis for the energy price paid by utilities for energy (whether or not the energy is RPS-eligible) from qualifying facilities (QFs) under the federal Public Utility Regulatory Policies Act of 1978. The two methodologies serve different purposes and respond to different statutory requirements. Compare D.05-12-042 with D.07-09-040 (as modified by D.08-09-024). A method or input used for one of these determinations will not necessarily apply to the other..

8 Section 399.15(c)(2).

9 *See* D.05-12-042, p. 8

natural gas price forecasts to be lower than New York Mercantile Exchange (NYMEX) forward prices.[10]

3.2.1.1. NYMEX Data

In. D.05-12-042, the Commission authorized staff to use all available forward gas contract data from contracts traded on the NYMEX, requiring staff to use a minimum of five years of data. At that time, there was a NYMEX market for forward gas contracts of six years. Today, the NYMEX market includes forward gas contracts of up to 12 years.

CalWEA, PG&E, and UCS argue that the methodology adopted in 2005 in effect supported the use of all available NYMEX data. They assert that the amount of data available has expanded from six to 12 years, but the principle of using all available market data should still be applied. Thus, these parties urge us to allow staff to use up to 12 years of NYMEX contract market data.

TURN, SCE, and SDG&E argue that it is unwise to rely on 12 years of NYMEX market data, because there is little liquidity in the market in the outer years. They each propose a different response. SDG&E supports continuing the current methodology, which uses the first six years of NYMEX data. TURN urges the Commission to adopt criteria for determining how many years of

---

[10] *See, e.g.*, M. Bolinger, R. Wiser, and W. Golove, "Accounting for Fuel Price Risk: Using Forward Natural Gas Prices Instead of Gas Price Forecasts to Compare Renewable to Natural Gas-Fired Generation" (August 2003) (LBNL- 53587, available at http://eetd.lbl.gov/ea/EMS/reports/53587.pdf; and "Accounting for Fuel Price Risk When Comparing Renewable to Gas-Fired Generation: The Role of Forward Natural Gas Prices" (January 2004) (LBNL-54751, available at http://eetd.lbl.gov/ea/ems/reports/54751.pdf). *See also* a recent shorter memorandum, M. Bolinger and R. Wiser, "Comparison of AEO 2008 Natural Gas Price Forecast to NYMEX Futures Prices," January 7, 2008 (available at http://eetd.lbl.gov/ea/ems/reports/53587_memo.pdf.)

NYMEX data to use for the MPR calculation. SCE proposes using only two years of NYMEX data and then making a transition to a different method.

In 2005, some parties argued that the six years of NYMEX contracts lacked liquidity in the outer years and thus were not reliable for the MPR. In 2008, the same argument is being made about the outer years of 12 years of NYMEX contracts. In three years, the NYMEX market has doubled the length of contracts that at least some buyers and sellers are willing to trade. This is an indication that the gas futures market places some value on such longer-term deals, even though they are relatively new. Participants in the California market for PPAs for electricity produced from CCGTs would also take this NYMEX information into account, though not all would give it the same weight.

It is important to remember that gas forecast information for the MPR is part of a modeling exercise, not a procurement transaction. The large utilities and TURN focus exclusively on what they see as the inadequacies of the NYMEX market data, without acknowledging that these data are based on forward contracts from a real market, with a structure, rules, and policies about price settlement and disclosure. Fundamental forecasts, by contrast, are not part of any organized market, and are not subject to testing by being bought and sold. These parties have not presented convincing arguments that greater reliance on fundamental forecasts, rather than working with NYMEX market data, would produce a more realistic set of inputs for the MPR gas forecast model.

It is our preference to use the most robust possible market data for the MPR model. Although the NYMEX data might not be as robust as we would like, using NYMEX forward price data for the MPR gas forecast is consistent with the general approach of trying to use the perspective of California electricity market participants in developing the MPR methodology. No party has suggested that the MPR's model developer of a California CCGT would simply ignore the outer years of NYMEX forward prices and rely solely on fundamental forecasts in estimating the cost of gas over a long-term contract.

In D.05-12-042, the Commission addressed the parties' concern about the outer years of the then six-year NYMEX forward price data set by giving staff discretion to use five or six years of NYMEX data. In comments on the proposed decision (PD), UCS recommends that we give staff a similar range of discretion now. This is a sound proposal. Staff is therefore authorized to use between nine years of NYMEX forward price data and all available years (currently 12) of NYMEX forward price data.[11]

3.2.1.2. Transition to Fundamental Forecast

Even if staff were to use all available NYMEX contract data (currently 12 years), it is necessary for the MPR model to rely on fundamental forecasts to project gas prices for the later years of the MPR model CCGT's long-term contract, when there are no NYMEX forward contracts. CalWEA, PG&E, TURN, and UCS propose changes in the fundamental forecast methodology; SDG&E recommends retaining the current method.

---

11 In its comments on the PD, SCE makes the belated suggestion, supported by PG&E, that the period of time from which NYMEX data are used in the MPR should be changed. Instead of using prices in the 22 days prior to the closing date of the last utility solicitation (as set by D.05-12-042, clarified by D.06-01-029), SCE and PG&E urge that "more current" NYMEX prices be used. This argument is made too late, without the proper opportunity for parties to provide information to oppose or support it, and thus is not being considered. In the interests of maintaining confidence in the stability of the MPR model, however, we note that the method in D.05-12-042 fixes the determination of the gas price in relation to an event (close of annual RPS solicitations) that occurs close in time to the submission of RPS bids and independent of events in the forward gas market.

In implementing the current MPR gas forecast methodology, staff uses all six years of available NYMEX data and then uses an average of public and private fundamental forecasts for years seven and later of the MPR model CCGT's contract. The transition between NYMEX forward prices and the fundamental forecast is accomplished by making a straight line interpolation between the last year of NYMEX data and the fourth year of the fundamental forecast (year 10) to create values for years 7, 8, and 9. *See* Res. E-4118**.**

TURN proposes eliminating the fundamental forecast altogether, and simply escalating the NYMEX contract values with an inflation factor. As CEERT points out, this method would guarantee that the MPR would never recognize any real (non-inflationary) increases in gas costs. This result seems arbitrary, and no party has provided a justification for it.

PG&E also proposes eliminating the fundamental forecast, and simply extending the NYMEX forward price data using a linear trend. No other party supports this proposal.

Both TURN and PG&E propose limiting the available data sources to only the NYMEX forward price data. The combination of NYMEX forward market data and fundamental forecasts, however, although it is somewhat inelegant, has the virtue of providing different sources of data for the MPR gas forecast. This creates a methodological "hedge" against unusual or distorted data resulting from the use of one source alone.

CalWEA and UCS propose maintaining the role of the MPR fundamental forecast, which is currently an average of public and private forecasts. *See* Res. E-4118. CalWEA seeks to close the gap between the fundamental forecast and forward prices by adding to the fundamental forecast the dollar value of the difference between NYMEX prices and the fundamental forecast prices for years

8-12 of the NYMEX contracts series. No other party supports this proposal. It adds complexity and, by relying on the fundamental forecast's absolute dollar values, risks placing too much emphasis on the fundamental forecast *per se*.

UCS, by contrast, proposes a more modest adjustment to the current MPR methodology. UCS suggests that the MPR continue to use its average of several fundamental forecasts. This average constitutes the MPR fundamental forecast. However, UCS proposes that the annual percentage rate of increase of the MPR fundamental forecast be used to escalate the last year of NYMEX values, rather than using the absolute dollar values of the MPR fundamental forecast to escalate the last year of NYMEX values for the remaining years of the forecast. UCS also urges that the current method of interpolation to make the transition from NYMEX data to fundamental forecasts be revised to use simply the last year of NYMEX data as the basis for the outer year fundamental forecast.

The UCS proposal, with some modifications, effectively addresses all three elements of the gas forecast methodology. It preserves the use of fundamental forecasts, but improves the manner in which they are used by retaining NYMEX data as the basis of the MPR gas forecast.

UCS's proposed use of only the last year of NYMEX data for the transition from NYMEX prices to the fundamental forecast, however, would result in a gas forecast that relies too heavily on the last year of NYMEX data.[12] Rather than relying on simply the last year of NYMEX forward prices to be the basis of the first year of the MPR fundamental forecast series, it would be more prudent to begin the MPR fundamental forecast based on a linear trend derived from

---

[12] The current method of straight-line interpolation set by D.05-12-042 is also intended to address this problem, but parties correctly note that it is unnecessarily artificial.

several years at the end of the NYMEX series. This method responds to parties' concerns about possible distortions to the MPR fundamental forecast from using too narrow a range of values to create the forward price for the first year of the MPR fundamental forecast. The linear trend smoothes out potential volatility in the outer years of the NYMEX data by fitting a curve to the forward prices, and thus reducing the impact of outliers or a single year's price. Staff is authorized to use at least the last three and as many as the last five years of NYMEX data to create the price for the first year to which the MPR fundamental forecast annual percentage change methodology will be applied.

3.2.2. California Basis Adjustment

In D.05-12-042, the Commission adopted the Gas Stipulation[13] with respect to short-term gas forecasts and certain other issues. One of those issues was the adjustment of Henry Hub forward gas prices to reflect the cost of delivery to California. The MPR has used NYMEX Clearport futures to calculate the California basis adjustment throughout the term of the model CCGT's contract.[14]

In its post-workshop comments, SCE identifies a potential inconsistency with using a NYMEX basis during the period that the MPR gas price model is based on a fundamental forecast methodology.[15] SCE suggests that the sources

---

[13] Parties to the Gas Stipulation were: the California Cogeneration Council, CalWEA, CCP, PG&E, SCE, and SDG&E. GPI also supported the Gas Stipulation.

[14] Three years of Clearport basis futures prices at the Southern California border and at PG&E's Citygate are currently averaged. The average is then applied throughout the rest of the contract term.

[15] As explained above, NYMEX market prices will be used for up to 12 years of the proxy CCGT's contract, while an MPR fundamental forecast will be used for the later years.

of the California basis adjustment should be the same as the sources of the gas forecast. That is, when the gas forecast is based on NYMEX prices, then the California basis adjustment should be based on NYMEX Clearport data. When the gas forecast is based on fundamental forecasts, then the basis adjustment used by the fundamental forecast should also be used.

No party opposes SCE's analysis. Adopting it as part of the MPR methodology would improve the consistency of the MPR modeling and simplify staff's task in developing data sources and checking their suitability. We will therefore make this small modification to the MPR methodology to require that the data sources for the California basis adjustment be the same as the data sources for the gas price forecast itself. That is, staff should use Clearport California basis adjustment data for the period of the gas forecast that uses NYMEX data, and the fundamental forecast's basis adjustment data for the period of using the MPR fundamental forecast. Since Clearport California basis adjustment data are not currently available for the entire period of time for which staff is authorized to use NYMEX forward price data, staff should describe how it is implementing the basis adjustment for the years using NYMEX data in the draft resolution. Staff should continue to apply the California basis adjustment to the MPR fundamental forecast in order to develop the final MPR California gas forecast used for the MPR calculation.

3.3. Capacity Factor

3.3.1. Background

In D.04-06-015, the Commission implemented the choice made in D.03-06-071 to develop a model proxy plant to use the costs associated with fixed-price electricity from new generation facilities and the value of different products to calculate the MPR. (*See* § § 399.15(c)(2) and (3).) D.04-06-015 adopted two proxy plants for the MPR: a baseload CCGT, and a "peaker" combustion turbine (CT). MPRs for each plant were then calculated by staff. A "blended" MPR was also calculated to take account of generation that is neither baseload nor peaking.

In the workshops and comments that preceded D.05-12-042, the MPR decision following D.04-06-015, the parties virtually unanimously supported the application of time of delivery (TOD) factors[16] to the CCGT-based MPR. This would eliminate the need for a CT-based peaking MPR and the "blended" MPR. Parties agreed that the application of TOD factors to the baseload MPR effectively takes into account "[t]he value of different products including baseload, peaking, and as-available electricity." (§ 399.15(c)(3).).

In comments prior to D.05-12-042, the parties also raised the issue of whether the MPR should continue to use the capacity factor of 92% adopted in 2004. This "technical" capacity factor assumes that the new CCGT of the proxy plant is running essentially all the time, and captures the effects of both maintenance and unplanned outages. CalWEA argued that the introduction of TODs would provide the proxy plant with a market pricing signal, leading the generator not to operate in hours where its marginal costs are greater than its marginal profits, which will be something below 92% of the time. D.05-12-042 adopted CalWEA's proposed methodology for calculating an "economic" capacity factor for the MPR proxy plant.

---

[16] Each utility determines TOD factors based on its analysis of the forward value of energy and capacity during different times of day and times of the year. This results, in practice, in each utility valuing electricity at different hours differently, sometimes significantly so. As relevant to the MPR calculation, the three large utilities use between six and nine TOD periods.

The basis of the methodology for this time-differentiated capacity factor is the TOD factors used by the three large utilities in procurement of electricity. The three large utilities are required to include their TODs for the upcoming procurement year in the public versions of their annual RPS procurement plans. *See* D.06-05-039; D.07-02-011; D.08-02-008.[17] Using the 2007 MPR as an example, the economic capacity factor is calculated by computing a capacity factor determined by the economic operating hours based on the weighted average of the three large utilities' TOD profiles and the costs of plant shut-down and start-up. This yields, for the 2007 MPR, a statewide capacity factor of 71%. (*See* Res. E-4118, Appendix D.)

3.3.2. Proposed Changes

Several parties propose changes to the MPR capacity factor methodology. Dissatisfaction with the current methodology focuses on the use of the utilities' TODs to calculate an economic capacity factor; in addition, there is also criticism of the TOD factors themselves.

TURN asserts that the current economic capacity factor results in over-payment to the model CCGT during some periods of time. Specifically, TURN asserts that "the current MPR model calculates a price that allows the proxy CCGT to recover all of its fixed and variable costs during 71% of the time, but then assumes that power during all other hours is valued at the same price."[18]

Moreover, TURN points out, the MPR using the economic capacity factor is then subject to a second application of TOD factors, when each utility

---

[17] The three large utilities filed their draft 2009 RPS procurement plans on September 15, 2008, in R.08-08-009.

[18] TURN's Reply Comments, p. 6.

evaluates PPA bid prices with respect to the MPR. When the utility compares the bids it has received to the MPR in the least-cost best-fit analysis, the utility uses its utility-specific TOD factors to adjust the MPR in the bid ranking process. [19]

SCE agrees with TURN's position that an economic capacity factor will result in an over-payment of capital costs when a plant runs at a higher capacity factor or during off-peak hours. SCE further argues that the current capacity factor methodology is inconsistent, since it assumes the revenues are adjusted by TOD factors for purposes of calculating the economic capacity factor, but the same TOD weighting is not reflected in the revenues in the cash flow analysis itself because the model calculates a levelized cost per kilowatt-hour of generation. The net effect, SCE asserts, is that the levelized revenue stream, calculated using the economic capacity factor, is over-stated through the application of the IOU-specific TOD factors when comparing RPS bids to the MPR.

The second area of dissatisfaction with the current capacity factor methodology is not with the use of an economic capacity factor, but with the use of utility-specific TODs to derive the economic capacity factor. CalWEA, CEERT, DRA, GPI, and TURN all express some level of dissatisfaction with the current utility TODs.

---

[19] Though not emphasized by any party, an additional distortion is embedded in the current method. PG&E, SCE, and SDG&E all have different TOD factors. The weighted average applied in the MPR calculation represents the TOD factors of none of them. Because the TOD factors are significantly different, for example between SCE and SDG&E, the statewide MPR builds in an inaccuracy upon which each utility then reapplies its own TODs.

CalWEA, the principal proponent of the economic capacity factor in 2005, continues to support that basic approach. However, CalWEA, too, proposes alternatives to the utilities' TODs. It makes instead two new proposals for a methodology to develop the economic capacity factor. The first is to rely on the California Independent Systems Operator's (CAISO) published statewide capacity factor.[20] This report uses data based on prices in the prior year's CAISO wholesale spot markets to derive an estimate of an historic economic capacity factor for a California CCGT. CalWEA's second proposal is to calculate the capacity factor directly, based on the prior year's wholesale prices NP-15 and SP-15 and daily gas prices, and the MPR heat rate and variable operation and maintenance values. Either method, CalWEA asserts, would result in a capacity factor using 2007 data and operating assumptions for the MPR proxy plant of approximately 68%.

Both PG&E and SCE oppose CalWEA's proposals. PG&E argues that these proposals would unjustifiably shift the MPR methodology to using historic data, rather than the parameters set out in D.05-12-042. SCE argues that the CalWEA proposal would not recognize all the revenues the proxy plant would earn on dispatch.

DRA advocates averaging the statewide capacity factor found in the CEC's Cost of Generation (COG) reports for the two most recent years.[21] Using the 2004

---

[20] *See* CAISO Market Issues and Performance: 2007 Annual Report, April 2008, ch. 2, available at http://www.caiso.com/1f9c/1f9c8b49e9f0.pdf.

[21] *See* Comparative Costs of California Central Station Electricity Generation Technologies (December 2007), CEC-200-2007-011-SF. It may be found at http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SF.PDF.

and 2005 COG reports would yield a capacity factor of approximately 57%, DRA states. No other party supports this proposal.

GPI urges us to adopt a different way of looking at the problem. GPI proposes a methodology that would create hourly demand factors, rather than the six to nine TOD periods currently used by the utilities. GPI claims that using the hourly factors would accurately reflect the operation of the proxy CCGT in every demand condition, producing a much more representative set of capacity factors.

Despite their differences on how to remedy the perceived problems with the MPR capacity factor methodology, the parties are unanimous on one point: no party proposes returning to the use of one CCGT and one peaking CT model for the MPR.

3.3.3. Discussion

The array of proposals may be summarized as follows. TURN proposes using the technical capacity factor without the weighted average TOD adjustments in the statewide MPR. CalWEA and DRA propose eliminating the TOD factors, but using other sources to develop an economic capacity factor. GPI proposes calculating many more, and more detailed, TODs than the utilities now use. SCE and PG&E support TURN's proposal, but also argue that, if an economic capacity factor is used, the TOD factors should be applied to realize additional revenues for the proxy CCGT.

In evaluating these proposals, it is important to remember that the fundamental purpose of the MPR in RPS procurement is to "establish a methodology to determine the market price of electricity. . . " (§ 399.15(c).) In D.05-12-042, the Commission recognized that the TOD factors are the method used by the utilities "to reflect the relative value of electricity to the [utilities] at various time periods." (D.05-12-042, p. 19.) The observation in D.05-12-042 that "[t]he utilities are the relevant market participants in setting the value to them of electricity during various time periods" *(ibid.*, p. 20) also remains valid today. We note that the Commission also determined that, to the extent possible for so technical a subject, the values of simplicity, consistency, and transparency were preferred for the MPR methodology. This principle remains sound and helps to guide our analysis.

None of the proposals made by CalWEA, DRA, and GPI resolves the excess weighting of economic factors in the current proxy plant model. They simply change the basis for determining the factors. Both CalWEA proposals incorporate the economic value of the energy output into the capacity factor, though each uses a different data set. The utilities would still apply their own TOD factors on top, as it were, of the MPR that incorporates the economic capacity factor. DRA's and GPI's proposals have a similar flaw.

We therefore adopt TURN's proposal to replace the economic capacity factor with a technical capacity factor (*i.e.*, to apply the utilities' TOD factors only once, rather than twice). The use of the technical capacity factor eliminates the distortions of the weighted average of TOD factors in the current method. It also results, when properly time-differentiated, in an MPR that better reflects the values of baseload, peaking, and intermittent products. Finally, the TURN proposal is simple, transparent and easy to implement.[22]

---

[22] SCE's alternative proposal, to keep the economic capacity factor and also apply the TOD-weighted capacity factor to the revenue calculation for the proxy plant CCGT, adds a layer of complexity in modeling the revenues that is not necessary to resolve the problems created by the current use of the utilities' TOD factors.

However, in order for the MPR calculation using the technical capacity factor to fairly represent the costs and revenue of the proxy CCGT, it must be paired with each utility's use of its publicly revealed TOD factors in evaluating bids, in order to produce a uniformly time-differentiated bid evaluation process. (See D.05-12-042, pp. 22-23.)[23]

3.4. Non-Gas Costs

3.4.1. Installed Capital Costs

3.4.1.1. Data Set

In D.05-12-042, the Commission set parameters for choosing data for the installed capital costs of the model CCGT. These included that the data be from plants built in California with approximately 500 megawatt capacity and the General Electric Company's GE F-Series turbine. Staff chose the then-recently completed Palomar and Cosumnes plants to provide these input data.

In preparation for the March 2008 workshop, staff requested comment from the parties on the addition of the Colusa plant, now under construction, to the data set for installed capital costs. The PPA between PG&E and E&L Westcoast for this project was originally approved in D.06-11-048. After the developer terminated the agreement, PG&E filed Application 07-11-009 for a certificate of public convenience and necessity (CPCN) to build the plant itself.

---

[23] CalWEA, CEERT, GPI, and TURN raise questions about whether the TOD factors are truly comparable among the utilities. They assert that TOD factors with significant differences among them may not be the most reliable basis for the MPR calculation. The utilities' TOD factors are reviewed annually with their RPS procurement plans in R.08-08-009. The TOD factors may also be considered in R.08-02-007, the long-term procurement proceeding. (*See* D.08-07-048.) Either of these proceedings could be a forum for suggestions for improving the TOD factors.

The Commission granted the CPCN and authorization for associated activities in D.08-02-019. Among the conditions of the grant was that the capital cost cap imposed in D.06-11-048 would be maintained when PG&E constructed the plant.

Ordinarily, the use of data from the Colusa plant would be a matter of staff's discretion, to be explained in the draft resolution calculating the MPR for 2008. Because there is a dispute among the parties about whether Colusa would meet the criteria set in D.05-12-042, we review the application of those criteria in this circumstance.

CalWEA and Shell argue that the addition of Colusa does not meet the criteria set out in D.05-12-042 because the project's transfer to PG&E was a distressed sale, thus presumably depressing its value. CalWEA also argues that the actual cost data for Colusa are not public; only the cost cap imposed in D.06-11-048 is publicly available. PG&E, SCE, and TURN argue that Colusa provides recent public data on costs for a plant that reasonably accords with the MPR proxy plant's characteristics.

D.05-12-042 determined that staff could use data from plants sold in secondary market transactions if sufficient data are publicly available for staff and parties to be able to evaluate the cost information; for example, "if the data have been reviewed in a formal Commission proceeding." (D.05-12-042, Finding of Fact 17, p. 54.) Both D.06-11-048 and D.08-02-019 concluded contested formal Commission proceedings. Even though the cost cap may not be the same as actual installed costs, on balance it is better to have more recent data to add to the small set of data on installed capital costs than to continue to base the MPR exclusively on historic capital costs (even if they are updated, as set forth below).[24] The use of capital cost data, including the capital cost cap, for the Colusa project meets the criteria set out in D.05-12-042 and is therefore within the discretion of staff. Staff may or may not choose to use such information, and should justify the choice in the draft resolution.

3.4.1.2. Capital Cost Escalation

3.4.1.2.1. Escalation of Historic Costs

Parties agree that capital costs, especially construction costs, have increased since staff began using the costs of the Palomar and Cosumnes plants in the MPR model. No other plants have been added to the data set since 2005, though staff may choose to add Colusa for 2008 and later years.

In D.05-12-042, the Commission did not consider the situation in which costs were increasing significantly but the data set for determining the values of those costs was not expanded. To address this, staff proposes that the MPR methodology be modified to allow for the escalation of "historic" capital costs to bring the older cost values more in line with 2008 values.

Most parties support this proposal. SCE questions whether it is necessary to adopt such an escalation now. We are persuaded that staff should have the option to make this adjustment, but we do not mandate its use. We therefore add to the MPR methodology the ability for staff to develop a factor by which to escalate the historic capital costs for the MPR proxy plant in certain limited circumstances. These would include, as is currently the case, a small and

---

[24] To the extent that actual capital costs for the Colusa plant are approved by the Commission and exceed the cost cap, staff would have discretion in future years to use the higher figure, subject as always to justification in the draft MPR resolution.

relatively older data set combined with a significant change in capital costs since the plants in the data set were constructed.

Parties express differing views with respect to the sources that should be used to provide values for updating the capital costs. Extensive comments were provided both on what sources to use, and whether the sources should be public or private. The choice of data sources is in the discretion of staff, so long as the need for such an escalation and the reasons for choosing particular data sources are clearly explained in the draft resolution. We note here only that, while the Commission prefers to use publicly available data when possible, staff should not be constrained to use only public sources for the information for escalating historic capital costs. The comments reveal that there are well-known and widely used private indices that may provide useful data. If private indices that are widely used in the industry provide some or all of the data, it is not likely that their use would introduce a particular bias into the data used by staff.

3.4.1.2.2. Escalation of Current Capital Costs

D.05-12-042 provides that the capital costs of the proxy plant should be escalated for a period of five years (until 2010) and then held constant, in order to reflect the fact that increased efficiencies in CCGTs would be likely to offset incremental capital costs in about five years. Staff sought comment from the parties on whether to generalize this provision to adopt a five-year time frame for escalation of installed capital costs.

CalWEA and SDG&E support the use of a "rolling" five-year time frame for escalation of capital costs. CalWEA asserts that there is no indication that technological advances will outpace cost increases in every year after 2010, so there is no reason to freeze the escalation in 2010.

PG&E, SCE, and TURN argue that the five-year cost escalation time frame should not be extended past 2010. PG&E argues that the use of the escalation in fact, and unjustifiably, increases the proxy CCGT's levelized costs in all years. SCE asserts that more efficient current technology justifies ending the cost escalation in 2010.

In setting the capital cost escalation methodology, D.05-12-042 did not look past the five years after 2005. The principle it expressed was that of seeking a balance point between technological improvement and cost increases. This principle also applies to later years. The record in this proceeding reveals no reason to believe that the dynamic relationship between cost increases and efficiency improvements will suddenly end by 2010. Indeed, the incentives and pressures attending the initiation of GHG regulation are likely to lead to continuing evolution of that dynamic. The MPR methodology should therefore provide for escalation of installed capital costs in each of the five years following the year of the solicitation for the RPS contract being evaluated.[25]

3.4.2. Generation Meter Multiplier (GMM) (Transmission Line Losses)

SCE urges that the current inclusion of a generation meter multiplier (GMM) to provide the costs for line losses during delivery of electricity from the generator to the utility should no longer be used. SCE points out that most PPAs with CCGTs require delivery at the busbar; thus, the generator incurs no delivery costs, and such costs should not be part of the MPR model.

---

[25] The choice of the factor to use for calculating this escalation remains in the discretion of staff, subject to being presented and explained in the annual MPR resolution.

No party disputes SCE's statement that CCGT contracts deliver at the busbar. CalWEA argues that changing the MPR methodology to recognize this fact would have the unintended consequence of subsidizing out-of-state RPS-eligible generation. CalWEA does not, however, provide a convincing explanation for its assertion of a subsidy. All MPR model contracts must bid an all-in price. If the MPR model provides for delivery at the busbar, then that model is applied to the evaluation of all project bids. The MPR itself does not take into account any characteristics of the renewable generation that is making the bid. It is the responsibility of the utility and the bidder, in the least-cost best-fit bid evaluation process, to be sure that transmission costs and possible transmission problems have been appropriately taken into account in evaluating the bid.

The MPR methodology should therefore be revised to remove the “GMM to load center” input. Alternatively, if it improves ease of calculation of the MPR, staff may assume a GMM to load center of 1.0.

3.5. Contract Length Greater Than 20 Years

D.05-12-042 established the MPR methodology for a PPA with a duration of between 10 and 20 years. CalWEA, supported by UCS and SDG&E, proposes that the Commission calculate the MPR for contracts of longer terms. CalWEA points out that utilities have submitted and the Commission has approved several RPS procurement contracts with terms of more than 20 years.[26]

TURN, PG&E, and SCE oppose CalWEA's request. TURN argues that the large role of the long-term gas forecast in the MPR calculation makes

---

[26] *See, e.g.*, Res-E-4138 (Dec. 20, 2007).

extended-term RPS contracts akin to speculation in the forward gas market. TURN urges that, if a longer-term MPR is approved, certain limitations should be placed on the approval of RPS contracts longer than 20 years.

The parties provide no reason to believe that calculating a 25-year MPR, for example, would not be feasible. Because parties have negotiated and presented for approval RPS contracts with extended terms, it is reasonable to allow staff to calculate the MPR so that such contracts can be evaluated consistently with contracts with more standard lengths. TURN's suggestions for limitations on longer-term contracts are more appropriately addressed at other points in the RPS procurement process, such as approval of the utilities' annual procurement plans and review of advice letters seeking approval of longer-term contracts. We emphasize that in providing authorization to staff to calculate a longer-term MPR, the Commission does not intend to encourage or discourage the use of any particular term of years for long-term RPS contracts.

3.6. GHG Compliance Costs

In D.07-09-024, the Commission authorized the use of a GHG adder for 2007 only, using the values from the model developed by Energy and Environmental Economics (E3 model) adopted in D.04-12-048. Consideration of further use of a GHG adder was set for 2008 in the Second Amended Scoping Memo and Ruling of Assigned Commissioner (February 25, 2008) for this proceeding.

Most commenting parties support the use of a GHG adder for 2008, but urge that it be used on an interim basis.[27] PG&E and SCE urge caution, because

---

[27] CalWEA, Central California Power, EPUC, PG&E, DRA, and TURN take this position. GPI and UCS support a permanent adder.

the California Air Resources Board (ARB) has not yet adopted a plan to implement the Global Warming Solutions Act of 2006, Assembly Bill (AB) 32 (Núñez/Pavley), Stats. 2006, ch. 488. The two utilities argue that premature action by this Commission could prejudge the outcome of ARB's process and, in the process, distort California market behavior.

As noted in D.07-09-24, AB 32 requires binding regulation of GHG emissions to begin not later than January 1, 2012. ARB is taking a variety of steps toward that point, including the recent release of its Climate Change Draft Scoping Plan (June 2008 Discussion Draft) (Draft Scoping Plan) on June 26, 2008.[28] Although ARB makes clear that the Draft Scoping Plan is very preliminary, it is also clear that significant regulation of GHG emissions from the electricity sector will be an element in the implementation of AB 32. This Commission, with the CEC, has made recommendations to ARB about some aspects of such regulation in D.07-09-017 and D.08-03-018. Both D.08-03-018 and the Draft Scoping Plan anticipate the creation of some market-based GHG emission control mechanisms. Parties have provided no reason to believe that the model CCGT for the MPR will not incur GHG compliance costs, and incur them no later than January 1, 2012. It therefore makes sense to change the MPR methodology now to make GHG compliance costs a permanent feature of the

[28] This document may be found at http://www.arb.ca.gov/cc/scopingplan/document/draftscopingplan.pdf. We take official notice of this document in accordance with Rule 13.9 of the Commission's Rules of Practice and Procedure.

MPR, rather than to adopt an interim GHG adder each year between now and 2012.[29]

Unlike most other elements of the MPR, however, the development of GHG regulation, leading to GHG compliance costs, is evolving quickly. The MPR methodology therefore should accommodate these changes without requiring unnecessary effort from staff and the parties. We recognize, however, that the rapid developments in this area may result in revisiting this aspect of the MPR in the future.

In applying the overarching market-based approach of the MPR model to GHG compliance costs, it is important to keep in mind that there is currently no GHG compliance market in California and/or in the area of the Western Climate Initiative (WCI)[30] from which to derive those costs. If and when such a market exists to determine the compliance costs (whether in the form of a market for allowances in a cap and trade system, a carbon fee, or a carbon tax), staff should

---

[29] Because GHG compliance costs will be a normal part of the MPR methodology, we will no longer refer to a "GHG adder," but will use the terminology of "GHG compliance costs."

[30] Planning for a regional strategy for reducing GHG emissions is occurring through the WCI. California participates in the WCI with the partner states of Arizona, Montana, New Mexico, Oregon, Utah, and Washington, and partner Canadian provinces of British Columbia, Manitoba, Ontario, and Quebec. Many other jurisdictions in the region have observer status at WCI, including the states of Alaska, Colorado, Idaho, Kansas, Nevada, and Wyoming; the Canadian province of Saskatchewan; and the Mexican states of Baja California, Chihuahua, Coahuila, Nuevo Leon, Sonora, and Tamaulipas. Information about the WCI, including the most current list of participating jurisdictions, may be found at http://www.westernclimateinitiative.org/. The WCI's "Design Recommendations for the WCI Regional Cap-and-Trade Program" may be found at http://www.westernclimateinitiative.org/ewebeditpro/items/O104F19865.PDF.

use those market-based costs as the basis for the model CCGT's GHG compliance costs in the MPR calculation.

At the present time, however, neither California nor the WCI has any market mechanisms in place for GHG compliance. CalWEA urges that the MPR methodology incorporate current market data from any existing market, whether or not it is in or near California. These include the GHG emissions market set up by the Regional Greenhouse Gas Initiative (RGGI),[31] as well as the European Union's Emissions Trading Scheme (ETS).[32]

No other party supports the use of data from these other markets. The structure and regulatory constraints of these markets are complex and not amenable to comparison with the MPR model CCGT. The record does not show any strong advantage to be gained by using data from these markets that would offset the confusion and uncertainties introduced by the many differences between these markets and the modeling of the costs incurred by the MPR proxy CCGT, which operates exclusively through a long-term contract with a California utility.

UCS, on the other hand, suggests a focus on information about the costs of GHG compliance for a California CCGT. This necessarily means that modeling of the CCGT's compliance costs should be undertaken, as was provided in D.07-09-024. GPI, TURN, and DRA support the use of modeling, though each proposes a different model. GPI proposes its own model; TURN advocates

---

[31] It includes the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. Information about RGGI may be found at http://www.rggi.org/home.

[32] Information about the ETS may be found at http://ec.europa.eu/environment/climat/emission/index_en.htm.

continued use of the E3 model adopted in D.04-12-048; and DRA proposes a multiplier for the 2007 GHG adder.

At this time, the use of modeling makes the most sense for determining the GHG compliance costs for the MPR model CCGT. Rather than using market data from markets that are very different from the projected California GHG compliance market sketched in the Draft Scoping Plan, using models based on publicly available assumptions and evaluations will provide the most transparent and accessible method. Both the E3 model and a model developed by Synapse Energy Economics, Inc.[33] were discussed at the workshop and in comments. Based on the methodologies used in these two models and parties' discussion of them, the modeling methodology for the MPR GHG compliance cost model should be:

- publicly available;
- based on multiple scenarios and sources of information;
- based on realistic and public assessments of policy proposals and scenarios;
- based on the most current reliable information that conforms to the other three criteria.

Staff has discretion to choose any model for GHG compliance costs that meets the criteria set out above. As with all other aspects of the MPR calculation, any choices about GHG modeling and inputs must be explained in the draft resolution presenting the MPR calculation.

Staff should also continue to assume that the proxy plant incurs GHG compliance costs beginning January 1, 2012, as set out in D.07-09-024.

[33] Information about Synapse may be found at http://www.synapse-energy.com.

Because it is difficult to predict when there will be market prices for GHG compliance costs that can be incorporated into the MPR model, it is important to build in the opportunity to revisit the MPR in order to update the methodology for determining GHG compliance costs. We therefore authorize the assigned Commissioner or assigned ALJ in R.08-08-009 or its successor to issue any rulings that may be necessary to initiate a review of the GHG compliance cost methodology for the MPR.

3.7. Issues Not Requiring Adjustments to Methodology

Staff and parties explored several additional areas at the workshop and in comments. Consideration of the thoughtful comments of the parties reveals that these topics do not require any changes to the MPR methodology. Rather, they are related to choices of inputs for the MPR model, which are in the discretion of staff. Staff should consider these comments in preparing the annual draft resolution calculating the MPR. As in prior years, staff will explain the choices of inputs made in the draft resolution.

These topics are:

- Data sources on installed capital costs;[34]
- Data sources for fixed and variable operating and maintenance costs;[35]
- Data sources for heat rate;[36]
- Data sources for escalation of prospective capital costs.[37]

---

[34] Comments were made by CalWEA, PG&E, SCE, UCS, and TURN.

[35] Comments were made by CalWEA and PG&E.

[36] Comments were made by CalWEA and PG&E.

[37] Comments were made by CalWEA, DRA, EPUC, and PG&E.

3.8. Confidentiality

In its pre-workshop comments, PG&E urges that the MPR be made confidential. That is, the calculation of the MPR, now performed by staff on the basis of the Commission's approved methodology and explained in a draft resolution, would not be publicly available. PG&E asserts that this step is necessary in order to protect ratepayers from RPS bid prices that are constructed to approximate the MPR, rather than to reflect the actual costs and desired level of profit of the bidders. TURN and SCE support both PG&E's assertion that the MPR has become a "price target" and its proposed remedy of confidentiality. SDG&E further argues in support of confidentiality for the MPR that the MPR is either or both market sensitive information protected by § 454.5(g) or a trade secret, defined in Civil Code § 3426.1 and privileged by Evidence Code § 1060.

This is not, strictly speaking, a matter of the MPR's methodology, except to the extent that it would change the mandate set out in D.04-06-015 that the MPR be publicly disclosed. Because of the significant public interest in the RPS program and the importance we have previously attached to public disclosure of information about the RPS program,[38] we address this question here.

We agree with CalWEA that SDG&E's argument has missed the mark. The MPR is neither market sensitive information nor a trade secret. It is a calculation made by this Commission, at the direction of the Legislature, as part of the administration of the RPS program. It is not the property of any private party, including any regulated utility. It may be relevant to the business of the

---

[38] *See* D.06-06-066.

IOUs, but that alone does not turn it into information that can or should be protected from public disclosure.

On the other hand, the claim of PG&E, SCE, and TURN that disclosure of the MPR harms ratepayers by driving up RPS prices would, if true, affect the administration of the MPR. None of these parties provides evidence that any particular bid price or set of bid prices has been dictated by the value of the MPR. CalWEA, GPI, and UCS all point out that prices for the materials used in constructing new renewable generation have been rising, and that there are shortages of some crucial equipment, such as wind turbines. Similarly, as discussed in this decision, costs to construct new CCGTs in California are also rising. If everything related to the construction of new electric generation in California is becoming more expensive, then it is not reasonable to infer that higher RPS bid prices over time are largely responding to a higher MPR. In the absence of any evidence of the influence of the MPR itself on RPS bid prices, to the exclusion of the economics of new generation construction, there is no basis to consider abandoning the public review and disclosure of the MPR.

PG&E and SDG&E also argue that whether an RPS contract price that is the subject of a Commission resolution is at, below, or above the MPR should not be disclosed. EPUC, GPI, Shell, and TURN argue that public disclosure of the relationship of the contract price to the MPR should continue.

The MPR methodology does not address the disclosure of contract prices submitted for Commission approval, but this issue has been raised by the parties and is of significance in the administration of the RPS program. It is important to note that disclosing the relationship of a contract price to the MPR does not constitute disclosure of the actual price, which all parties agree should be kept confidential. Moreover, the information presented about the relationship of a contract price to the MPR is never current. All RPS procurement contracts submitted for Commission approval refer to a historic MPR, not the MPR that will be calculated for a future year. Many contracts are submitted more than a year after the publication of the MPR for the year of the solicitation. Parties advocating that the relationship to the MPR be kept confidential have provided no reason to believe that the information that a particular contractual arrangement was above or below the MPR from two or three years prior could have any impact on behavior of RPS market participants in the future.[39] We will direct staff to continue to require disclosure in advice letters and resolutions of whether an RPS contract price submitted for Commission approval is at, below, or above the MPR.

4. Next Steps

Energy Division staff will calculate the MPR for 2008 and later years based on the methodology set forth in this decision and present it annually, as in previous years, in the form of a draft resolution. Where the decision provides guidance to staff about the use of specific inputs, staff should consider that guidance, but staff retains its discretion to choose inputs to the MPR model that most appropriately reflect the Commission's market-based approach to implementing the model.

With respect to the inputs to the 2008 MPR, staff has available all the party comments submitted prior to this decision. With respect to the inputs to the

---

[39] Since the actual monetary difference between the contract price and the MPR remains confidential, as CalWEA points out in its comments on the PD, the publication of the relationship of the contract price to a prior MPR conveys, in the end, little information that would be useful to future bidders in the complex RPS procurement process.

MPR model for 2009 and later years, staff has discretion to seek comments and other participation from the parties prior to, as well as after, preparation of the draft resolution calculating the MPR for that year. The assigned Commissioner or assigned ALJ in R.08-08-009 or its successor is authorized to issue any rulings necessary to allow effective participation of the parties in developing the inputs to be used for the MPR model in 2009 and later years.

We do not expect to revisit the MPR methodology again in the context of the current RPS program. If there are future legislative changes to the MPR, we will take steps to conform the MPR promptly to any new legislative mandates. If significant new state, regional, or national developments impact the determination of GHG compliance costs for the MPR, we will review that aspect of the MPR methodology as appropriate.

5. Comments on Proposed Decision

The proposed decision of ALJ Simon in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments on the PD were filed on October 6, 2008 by CalWEA, California Cogeneration Council, Large-scale Solar Association, and Solar Alliance (jointly; collectively, CalWEA); Energy Producers and Users Coalition and Cogeneration Association of California (jointly; collectively, EPUC); GPI; PG&E; SDG&E; SCE; TURN; and UCS. Reply comments were filed on October 14, 2008 by CalWEA, EPUC, PG&E, TURN, and UCS.

The comments focus on three areas: gas forecast, capacity factor, and GHG compliance costs. Some comments also address issues related to capital cost and confidentiality of the MPR calculation. All comments and reply comments have been carefully considered.[40]

The principal areas of revisions in the text of the PD are noted here.

The basic approach of the gas forecast for the MPR has been clarified, with more explicit reference to D.05-12-042. Some comments point out ambiguities in parts of the discussion of the gas forecast. These parts have been expanded and clarified. The scope of staff discretion has been made clearer.

The discussion of the relationship of the utilities' TOD factors to the time-differentiated MPR has been expanded and clarified.

The discussion of the escalation of capital costs has been expanded and the scope of staff discretion has been clarified.

The discussion of GHG compliance costs has been revised to characterize the models of GHG costs more accurately and to explain the scope of staff discretion more precisely.

Additional changes have been made to address less significant issues raised by the comments, to correct minor errors, and to improve consistency.

6. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and Anne E. Simon and Burton W. Mattson are the assigned ALJs in this proceeding.

---

[40] Some comments and reply comments, including those of CalWEA, GPI, SCE, and SDG&E, present factual material not in the record of this proceeding as the basis for some of their recommendations on the PD. Rule 14.3 provides, however, that comments "shall make specific references to the record." This new factual material has not been used in making revisions to the PD.

Findings of Fact

1. It is reasonable to continue the use of the CCGT proxy plant model methodology set out in D.04-06-015 and D.05-12-042 in calculating the MPR.

2. It is reasonable to make adjustments to the details of the proxy plant model MPR methodology on the basis of experience to date with the use of the MPR in long-term procurement in the RPS program.

3. Elements of the MPR methodology for which adjustments may reasonably be made at this time are:

- use of NYMEX forward contract data and fundamental forecasts in the MPR long-term natural gas price forecast;
- determination of the California basis adjustment for natural gas prices;
- determination of the capacity factor of the MPR proxy plant CCGT;
- escalation of historic installed capital costs;
- continued application of a five-year escalation of capital costs;
- elimination of the input for "GMM to load center;" and
- calculation of the MPR for contract lengths greater than 20 years.

4. In view of the impending implementation of GHG regulation in California, it is reasonable to include costs of compliance with regulations governing GHG emissions as a permanent feature of the proxy plant model MPR methodology.

5. In view of the rapid developments in GHG regulation, it is reasonable to set criteria for the modeling of GHG compliance costs to require that the model include at least:

- public availability;
- use of multiple scenarios and sources of information;

- use of realistic and public assessments of policy proposals and scenarios; and
- use of the most current reliable information that conforms to the other three criteria.

6. Because of the public importance of the RPS program, it is reasonable to continue to make the MPR calculation publicly available and to require utilities to disclose whether procurement contracts for RPS-eligible resources submitted for Commission approval are priced at, below, or above the MPR.

Conclusions of Law

1. Staff should be authorized to continue to use the CCGT proxy plant model methodology set out in D.04-06-015 and D.05-12-042 in calculating the MPR.

2. Adjustments to the details of the proxy plant model MPR methodology should be made on the basis of experience to date with the use of the MPR in long-term procurement in the RPS program.

3. Elements of the MPR methodology for which adjustments should reasonably be made at this time are:

- use of NYMEX forward contract data and fundamental forecasts in the MPR long-term natural gas price forecast;
- determination of the California basis adjustment for natural gas prices;
- determination of the capacity factor of the MPR proxy plant CCGT;
- escalation of historic installed capital costs;
- continued application of a five-year escalation of capital costs;
- elimination of the input for GMM to load center; and
- calculation of the MPR for contract lengths greater than 20 years.

4. In view of the impending implementation of GHG regulation in California, costs of compliance with regulations governing GHG emissions should be included as a permanent feature of the proxy plant model MPR methodology.

5. In view of the rapid developments in GHG regulation, criteria for the modeling of GHG compliance costs should be set. These criteria should require that the model include at least:

- public availability;
- use of multiple scenarios and sources of information;
- use of realistic and public assessments of policy proposals and scenarios; and
- use of the most current reliable information that conforms to the other three criteria.

6. Because of the public importance of the RPS program, the MPR calculation should continue to publicly available and utilities should continue to be required to disclose whether procurement contracts for RPS-eligible resources submitted for Commission approval are priced at, below, or above the MPR.

7. In order to allow PPAs resulting from the 2008 RPS solicitations to be concluded expeditiously, this order should be effective immediately.

O R D E R

IT IS ORDERED that:

1. The market price referent (MPR) required to be calculated for the renewables portfolio standard program shall be calculated for 2008 and later years in accordance with the methodology set out in Decision (D.) 04-06-015 and D.05-12-042, with the adjustments and improvements set forth in today's decision.

2. Energy Division staff is authorized to choose appropriate inputs for the annual calculation of the MPR and to disclose and explain those inputs in the draft resolution presenting the MPR calculation for Commission approval.

3. The assigned Commissioner or assigned Administrative Law Judge in Rulemaking 08-08-009 or its successor is authorized to issue any rulings that may be necessary to:

a. allow effective participation of the parties in developing the inputs to be used for the MPR model in 2009 and later years; and

b. Initiate a review of the greenhouse gas compliance cost methodology for the MPR when and as appropriate.

4. R.06-02-012 remains open.

This order is effective today.

Dated October 16, 2008, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
Commissioners