AES/jva 7/7/2005

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

ADMINISTRATIVE LAW JUDGE'S RULING SETTING SCHEDULE FOR BRIEFS FOLLOWING 2005 MARKET PRICE REFERENT WORKSHOPS

The Administrative Law Judge's (ALJ) Ruling Setting Schedule for Consideration of 2005 Market Price Referent (MPR) Issues (May 24, 2005), set a general schedule for workshops and a schedule for submission of post-workshop briefs on MPR issues. As a result of the workshops, it appears that the process of setting the 2005 MPR would benefit from more detailed suggestions to the parties about topics that could be covered in the briefs.

In order to give parties time for more thorough review and consideration of these topics, the schedule for briefing will also be revised.

Parties are free to address in their briefs any topics raised in the workshops and in this ruling.

Topics for briefs

A. MPR non-gas inputs and methodology

1. Identify the operational characteristics of a new proxy baseload (CCGT) and peaker resource (CT) located in the CAISO control area. The operational characteristics include the assumed capacity factor and heat rates of these plants.

2. Identify criteria for selecting non-gas inputs for a new resource in the CAISO control area.

    a) Should the CPUC use a market survey of capital costs, capital costs associated with a competitive bid, or secondary market data? Please provide the rationale for your recommendation and provide available data sources.

    b) Applicability of using the cost data for gas-fired plants in other regions for benchmarking purposes?

        (1) EIA data (Western Region of U.S.), Northwest Power Pool data (North West U.S.) etc.

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

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

    a) How should non-gas inputs, such as capital costs, be adjusted?

5. Identify the operating assumptions that should be used to derive the cost of capital inputs.

    a) Is the generation developer a single plant owner with a single long-term power purchase agreement (project or asset-based financing)?

    b) Does project or asset-based financing between a developer and a utility imply that the developer should have access to utility cost financing?

    c) Alternatively, is it more reasonable to assume that the generation developer has a portfolio of generation resources that depends in part on having sufficient cash flows from a long term power purchase agreement to initiate development funding, but will ultimately finance its project using the quality of its entire balance sheet?

    d) Given the operating assumptions that are selected above, please indicate the appropriate ROE, LT debt, and capital structure that you recommend be used in the financing assumptions for the MPR calculation. Please provide any tests, validation, or research that can be used to confirm that the proposed inputs are appropriate.

6. Discuss the Staff straw proposal for calculating capacity factor for CT proxy.

    a) Use gas forecast and other non-gas inputs to compute 'cross-over' capacity factor point when a CT becomes more costly than a CCGT.

7. The 2004 MPR Cash Flow model applies an annual escalation factor to the property tax rate. Going forward, should the CPUC keep the property tax rate fixed and use straight-line depreciation to derive annual property tax?

8. Identify cross-over issues associated with the 2005 MPR and the implementation of a MPR Time of Delivery profile.

In addressing these questions, parties may wish to consult:

a) Minutes from June 21, 2005 MPR non-gas workshop (to be circulated to parties on 7/11/05)

b) E3 Presentation CT Proxy Cap Factor 6/21/05 (circulated to parties on 6/24/05)

c) E3 Presentation MPR Cost of Capital Inputs 6/21/05 (circulated to parties on 6/24/05)

d) 2004 MPR Cash Flow Model Final 2004 MPR Resolution 7/5/05 (circulated to parties on 7/7/05)

B. MPR Gas Inputs and Methodology

See Attachment #1 – "Gas Forecasting Summary of Positions and Questions" for discussion and questions. Please address all questions in parts 1--3 of Attachment #1.

In addressing these questions, parties may wish to consult:

a) Minutes from June 20, 2005 MPR gas workshop (to be circulated to parties on 7/11/05)

b) 20004 MPR Gas Forecast V1 5/19/05 (circulated to parties on 5/22/05)

c) 2005 Cost of Carry Gas Forecast Model (circulated to parties on 5/22/05)

d) Cost of Carry Model Documentation (circulated to parties on 5/22/05)

e) SCE Cost of Carry Presentation MPR Workshop 6/20/05 (circulated to parties on 6/24/05)

f) CEC Gas Presentation MPR Workshop 6/20/05 (circulated to parties on 6/24/05)

g) CEC's "Preliminary Reference Case in Support of the 2005 Natural Gas Market Assessment" (http://www.energy.ca.gov/2005publications/CEC-600-2005-026/CEC-600-2005-026.PDF)

C. Time-differentiation of MPR

1. Of the four different methodological approaches ((1) historically observed market data (GPI), (2) forward looking market data (PG&E), (3) QF pricing (SCE), and (4) peaker and baseload proxy blend (refinement of existing method)), which approach do you feel satisfies the following goals of the MPR and why? (See attached Appendices A and B, and the link to Attachment 2 (http://www.cpuc.ca.gov/PUBLISHED/RULINGS/47717.htm) for details);

   a) Reasonable estimate of the value of energy and capacity provided by the resource.

   b) Provides adequate accuracy without too much complexity.

   d) Repeatable in future years.

   e) Are there other important attributes of the TOD method that the Commission should consider?

2. In your opinion, is it important that all utilities (PG&E, SCE, and SDG&E) adopt the same methodology for Time of Day allocation of the MPR? For example, the Time of Day calculation spreadsheet shows significant differences in the annual average MPR for the solar output shape between SCE's TOD proposal and PG&E's TOD proposal.

3. What specific rules regarding the use of TOD factors will need to be developed?

4. If each IOU calculates its own IOU-specific TOD factors and applies them to the adopted MPR, what TOD review does the CPUC need to conduct? What are the metrics for evaluating TODs?

5. Assuming MPRs are time differentiated, how should TODs be incorporated into bid prices, LCBF evaluation process, and SEP determination?

In addressing these questions, parties may wish to consult:[1]

a) Minutes from June 27, 2005 MPR TOD workshop (to be circulated to parties on 7/11/05)

b) Proposals for time–differentiating MPRs (Appendix A)

c) MPR TOD proposals from SCE, PG&E, SDG&E, and GPI (Appendix B)

d) GPI Presentation TOD Proposal 6/27/05 (circulated to parties on 7/7/05)

[1] Materials Distributed on 7/7/05 as part of Attachment #2 to this ruling can be found at http://www.cpuc.ca.gov/PUBLISHED/RULINGS/47717.htm

e) E3 Presentation TOD Profile Benchmarking 6/27/05 (circulated to parties on 7/7/05)

f) E3 Presentation TOD Profile Comparison 6/27/05 (circulated to parties on 7/7/05)

g) GPI TOD model – "EAP Calculator" (circulated to parties on 7/7/05)

h) Attachment #2 - MPR Time of Delivery Proposal Comparison model

Schedule

July 29, 2005	Opening briefs addressing unresolved workshop issues and topics set forth above to be filed and served
August 10, 2005 .	Any stipulations among parties on workshop issues to be filed and served
August 12, 2005	Reply briefs to be filed and served

IT IS RULED that:

1. Post-workshop briefs on issues related to the 2005 MPR may include discussion of the topics set out above.

2. The briefing schedule for post-workshop briefs on 2005 MPR issues are revised as set forth above. Opening Briefs shall be filed and served by July 29, 2005, and reply brief by August 12, 2005.

Dated July 7, 2005, at San Francisco, California.

/s/ ANN E. SIMON by
LYNN T. CAREW

Anne E. Simon
Administrative Law Judge

APPENDIX A
Descriptions of Proposed Time of Day Allocation Methods
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Outlined below are the Time of Day (TOD) allocation methodologies proposed at the June 27, 2005 MPR TOD workshop by parties and CPUC Staff.

Normalized 2004 MPR Method

The first approach is based on the method established in the 2004 MPR process. This method developed an all-in estimate of a 'baseload' and a 'peaking' plant Market Price Referent (MPR) based on gas and non-gas assumptions. The 'baseload' plant was based on a combined cycle combustion turbine and the 'peaking' plant was based on a combustion turbine which applied in an on peak period of 5 days a week by 8 hours a day by 12 months a year.

Therefore, one approach is to set the MPR for energy delivered in the 5X8X12 peak period based on the 'peaking' plant, and to set the MPR for delivered energy during the other hours with the 'baseload' plant. This method would then 'normalize' the results so that the annual average MPR is equal to the baseload MPR. Therefore, a baseload plant operating with a flat output profile would collect on average the baseload MPR value. A resource that operated in the on-peak period only would on average collect the peaking MPR.

Investor-owned Utility (IOU) TOD Profile

An alternative approach to developing the MPR value by time of energy delivery is to use utility proposed Time of Day profiles. Each utility has provided in its comments a proposal. The PG&E TOD profiles are based on their forward market forecasts of expected energy price differentials. The SCE TOD profiles are based on the energy and capacity payments to Qualifying Facilities. SDG&E has offered to develop TOD profiles and indicates that it has information necessary to use either method.

In all cases, these TOD profiles have the same structure. Each utility would provide a TOD factor that varied by time-of-use period that represented a relative 'all-in' energy and capacity value in that period. The TOD factors are developed such that a flat output profile over the course of the year would have an average TOD factor of 1.

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These factors would then be multiplied by the 'baseload' MPR to determine the MPR for deliveries in each TOU period.

Blended CT / CCGT

The blended CT / CCGT approach would compute a TOD factor for each utility based on their defined time of use period as a weighted average of 'peaker' and 'baseload' MPR in each period.

To determine the weighting in each TOU period, the 'peaker' would be assumed to operate on-peak until it had reached the number of annual operating hours assumed in the development of the 'all-in' 'peaker' MPR cost. In the other hours, the baseload plant would assume to be operating. In the presentations of results based on the 2004 MPR input assumptions, this resulted in the 'peaker' getting a 100% weight in the summer peak period, the 'baseload' plant getting 100% weight in the off-peak period, and the shoulder periods getting a blend depending on the remaining operating hours of the 'peaker' unit.

GPI TOD Profile

The Green Power Institute (GPI) proposes a set of TOD adders based on observed historical market prices from the California PX. The proposal would provide TOD adders for 24 hours X 12 months X weekday / weekend (576 periods).

The method would work by soliciting bids that provide estimates of quantity delivered in each of the TOD periods, and then compute an average annual adder for the bid profile. This annual average adder would then be added to the baseload MPR value to determine the MPR for the bid. The SEP payment would be the difference between the computed MPR value and the bid price which is a constant value over the year.

(END OF APPENDIX A)

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Note: Circulated by the parties - written responses to TOD questions in June 27, 2005 MPR TOD workshop agenda.

PG&E

How do you calculate TOD profiles?

PG&E develops RPS Time of Delivery (TOD) factors by calculating the average forward price over a set of hours in a particular TOD period as a percentage of the forward price over all hours in the year. The creation of the PG&E proprietary hourly forward prices first begins with market forward energy price information gathered from broker quotes and exchange prices. The energy market currently reflects that there is no formal installed capacity market or separately traded resource adequacy product.

These market energy forwards are then used to develop prices for subperiod blocks of power and finally to create PG&E proprietary hourly price streams by scaling an hourly price shape for each month to the monthly forward price. The proprietary hourly price shapes are created by calibrating exponential functions of hourly load to prices. For use in the 2005 RPS Solicitation, PG&E looked at prices from a series of years in the future and chose to create TOD factors for nine TOD periods.

PG&E's proposal is to refresh the MPR TOD factors for each RPS solicitation. The data sources used to derive the TOD factors are PG&E's proprietary market forward price curve and hourly load profiles.

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What do you use TOD profiles for (all-source, RPS, QF etc.)?

PG&E uses TOD factors both in the RPS evaluation process and to determine payments to RPS generators. In the RPS evaluation process, PG&E uses TOD profiles to help measure the market value of bids. For example, with baseload RPS products, PG&E compares the contract cost of each bid price time differentiated by the TOD factors contained in the protocol to the market value of time-differentiated deliveries. In determining the market value of each bid, the TOD factors are updated (using the same methodology) to reflect current market conditions at the time of bid evaluation. In determining payment to a generator during a particular TOD period, the contract price is adjusted by a TOD factor reflecting the value of power delivered during that period.

The same underlying PG&E proprietary hourly price streams are used to create both PG&E's proposed TOD profiles for use in the RPS MPR process and as the foundation for market valuation in other PG&E all-source solicitations. If several solicitations are to be evaluated on the same day, the same underlying price inputs would be used across all solicitations.

Do you think TOD profiles are appropriate for the MPR? If so, what is your proposal for applying a TOD profile to the MPR?

TOD profiles are appropriate for use in the MPR process. PG&E's recommendation is to have Utility Specific MPR TOD factors. For the 2005 RPS MPR Cycle PG&E proposes to use the TOD factors of its 2005 RPS Solicitation protocol shown below in Table VIII.2 to time differentiate the MPR. These factors would be fixed for each RPS solicitation cycle. They would not change based on contract start date or the duration of the contract. These time of delivery factors would be used to adjust the CPUC-developed statewide Baseload MPR to reflect each generator's proposed profile for use in determining if a bid is above the MPR and may qualify for Supplemental Energy Payments.

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2005 PG&E RPS Solicitation Protocol

Table VIII.2: Time of Delivery (TOD) Periods & Factors

Monthly Period	Super-Peak[1,4]	Shoulder[2,4]	Night[3,4]
Jun - Sep	1.543	1.024	0.747
Oct.- Dec., Jan. & Feb.	1.310	1.065	0.787
Mar. - May	1.104	.920	0.673

Definitions:

1. Super-Peak (5x8) = HE (Hours Ending) 13 - 20, Monday - Friday (*except* NERC holidays).
2. Shoulder = HE 7 - 12, 21 and 22, Monday - Friday (*except* NERC holidays); and HE 7 - 22 Saturday, Sunday and *all* NERC holidays.
3. Night (7x8) = HE 1 - 6, 23 and 24 all days *(including* NERC holidays).
4. NERC (Additional Off-Peak) Holidays include: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. Three of these days, Memorial Day, Labor Day, and Thanksgiving Day occur on the same day each year. Memorial Day is the last Monday in May; Labor Day is the first Monday in September; and Thanksgiving Day is the last Thursday in November. New Year's Day, Independence Day, and Christmas Day, by definition, are predetermined dates each year. However, in the event they occur on a Sunday, the "NERC Additional Off-Peak Holiday" is celebrated on the Monday immediately following that Sunday. However, if any of these days occur on a Saturday, the "NERC Additional Off-Peak Holiday" remains on that Saturday.

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SCE

How do we calculate TOD profiles?

As described in our pre-workshop comments, we recommend continuing to use the current methodology for developing uniform (non-time differentiated) MPRs, and developing TOD MPR factors ("profiles") that spread the uniform MPRs to time of day periods. The TOD MPR profiles should be "all-in" (energy and capacity), and developed by blending separate capacity and energy allocation factors, as shown in Appendix B of our pre-workshop comments.

TOD profiles for new RPS contracts should be consistent with the energy and capacity allocation factors authorized by the CPUC for all QF contracts. Both RPS bids and the MPR are based on an all-in price. SCE developed a TOD profile for time-differentiating these all-in prices based on existing QF energy and capacity allocation factors and an assumed mix of capacity and energy prices in the all-in MPR price, as shown in Appendix B of its pre-workshop comments.

The current capacity allocation factors were developed based on relative loss of load probability (LOLP) analysis performed in the mid 1990's. The current energy allocation factors were based on TOD-specific IERs which were also developed in the mid 1990's. Both sets of factors were developed using production simulation model analysis to simulate the operation of generating resources to serve load in SCE's service area (taking imports and exports into consideration) for the purpose of developing QF payments. Since the MPR calculation is based on current values, SCE believes that using mid-1990's allocation factors is a reasonable interim approach.

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What do you use TOD profiles for?

Typically, SCE does not use "all-in" TOD profiles. For QF purchases and demand side management (DSM) cost-effectiveness analysis, energy and capacity avoided costs are calculated separately. For its renewable and all-source procurements, SCE uses a variety of analytical approaches, including the direct use of production cost modeling. Typically, market products do not match the TOD periods used for QF and DSM purposes, and instead follow profiles such as 6x16 or 7x24 delivery or may involve dispatchable power--paying for capacity based on availability and paying for energy only when needed at the strike price of the contract.

Should TOD profiles be used and, if so, how?

For an all-in price bidder, the all-in TOD profile values should be applied to the baseload MPR. These TOD factors should sum to unity when time-weighted across a year. The MPR in any specific TOD period should be the product of the baseload MPR and the TOD factor for that TOD period. The contract between an all-in price bidder and the IOU should reflect these time-differentiated relationships.

SDG&E

What is SDG&E's TOD Proposal?

SDG&E proposes that the utilities be provided the flexibility to use TOD when it makes sense for a particular contract. SDG&E is amenable to developing TOD factors, if that is the Commission direction, to replace the peaking MPR approach for peaking renewables.

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How did SDG&E calculate TOD profiles in 2004 MPR?

SDG&E did not require a TOD approach in its 2004 RFO. SDG&E complied with the Commission direction regarding application of the 2004 MPR.

How does SDG&E calculate TOD profiles in other activities?

- Electric Procurement
  - TOD profiles are developed using "all-in" prices in SDG&E's weekly procurement least cost dispatch analysis
  - Historical non-standard product prices are compared to historical standard product prices to develop hourly market TOD profiles
  - Forward hourly market prices from proprietary publication resources are then applied to the historical TOD profiles to shaped market based prices.
- QF Procurement
  - Energy and capacity factors were calculated separately for standard offer type contracts
  - The TOD factors were developed based on 1995 production cost models for the specifically defined periods
  - These factors will be updated in phase 2 of Avoided Cost Proceeding in 2005
- Energy Efficiency Cost Benefit Analysis
  - "All-in" 8760 hourly price profile was developed by E3
  - Based on 1998-2000 PX data

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What does SDG&E use TOD profiles for?

- Procurement
  - Hourly profiles for Standard and Shaped Products are developed for weekly least cost dispatch modeling
- QF pricing
  - SRAC Energy
  - SRAC As-Available Capacity
  - SO4 As-Delivered Capacity
  - Firm Capacity summer/winter differentiation
- Non-procurement – TOD/TOU
  - Rate Design – charges to customers - summer/winter only commodity distinction currently
  - For use in Energy Efficiency cost benefit analysis
  - Currently being considered in DG cost/benefit and in various demand response proposals

Does SDG&E use different TOD profiles for different procurement activities?

- Yes as previously stated
  - To develop hourly profiles for Standard and Shaped Products for weekly least cost dispatch modeling
  - For QF pricing

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Does SDG&E think TOD profiles are appropriate for the MPR?

- TOD profiles were not required for the 2004 MPR methodology since all resources other than solar, are either baseloaded or, in the case of wind, have a production profile with a TOD factor close to 1.0.
- SDG&E is amenable to developing TOD factors, if that is the Commission direction, to replace the peaking MPR approach for peaking renewables.

GPI

The GPI proposes that the utilities employ full TOD profiling in the 2005 RPS solicitation process. A set of TOD profiles, described mathematically as a set of 576 adders (monthly 24-hr curves for weekdays, and monthly 24-hr curves for weekends/ holidays), will be adopted for each utility company. The profiles will be used to convert bid prices and generation profiles to an Equivalent Annual Price (EAP), which is the equivalent 8,760-hour, annual-average, all-in price of electricity. The EAP allows renewables in a given solicitation with vastly different generating profiles to be compared unambiguously with respect to cost. This is the first step in least-cost / best-fit bid ranking. Bidders will be required to specify their expected generating output profile as part of their bids. At least one of the utilities (SCE) already requires this information in their bid protocols.

After the utilities have prepared their short lists for their 2005 solicitations, and the MPR has been released by the Commission, the EAPs of the short-listed bids will be compared to the MPR for purposes of determining the need for SEPs. It is for this step in particular that the GPI proposal employs the use of adders, rather than multipliers, in the description of the TOD profiles. The use of adders ensures that the difference in value for every hour of the year between an MPR-limited contract price and a bid price is a constant value, equal to the difference between the bidder's EAP and the

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MPR. This being the case a constant-valued (non time-differentiated) SEP payment can be employed, and SCE's only concern with the method is satisfied.[2]

Finally, when the generators deliver power to the utilities, they will be paid on the basis of TOD-profiled revenues based on their actual deliveries of energy (same TOD profiles). Energy deliveries for ISO Participating Generators already are required to be scheduled and metered on an hourly basis, so all of the data necessary for hourly pricing already will be readily available.

The first step in implementing full TOD profiling is to adopt a set of TOD adders for each utility. We strongly recommend the adoption of profiles based on publicly accessible data, such as E3's NP-15 and SP-15 profile, so that they will be completely transparent to all parties. The profiles will be incorporated into each utility's RPS solicitation documents. In addition, the solicitations will be amended to seek hourly generating profiles by month for all bidders, if they don't already require that information.

Attached to this proposal is a spreadsheet model that computes an annual-average adder for any given combination of generating profile and TOD adders. As distributed, the model contains a set of TOD adders that are based on statewide CalPX data, and the output profile for the sample solar generator that the GPI presented at the June 27, 2005, workshop. All inputs to the model are entered into the first two tabs of the spreadsheet, and are colored red. The TOD dataset in the model should be replaced by the dataset adopted for each utility for a given solicitation, while the output profile will

[2] Richard Davis of SCE stated at the June 27, 2005, TOD workshop that if he could be satisfied that the SEP payments based on the GPI method yielded exactly the amount of revenue that is the difference between what the MPR-limited contract will pay, and what was bid, he would endorse the GPI method. That condition is met when TOD profiles are expressed with adders.

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be replaced with each bidder's projected profile. The annual-average adder calculated by the model represents the difference, in cents per kWh, between the bid price for the energy profile being offered, and the EAP.

We repeat below the results of the example presented at the June 27, 2005, workshop, comparing bids from baseload and solar generators. All values in the table are ¢/kWh.

	Solar	**Baseload**
Bid Price	9.5	7.0
Adder	2.1	0.1
EAP (EAP = bid price – adder)	7.4	6.9
MPR	6.9	6.9
Contract Price	6.9	6.9
SEP (constant all hours)	0.5	0.0

Which bid is preferred? It depends on the least-cost / best-fit needs of the soliciting utility.

(END OF APPENDIX B)

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2005 MPR Gas Forecasting Summary of Positions
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Background

At the June 20-21, 2005 MPR workshops, parties presented and discussed several issues regarding the appropriate methodology and proposed improvements for the MRP natural-gas price forecast. To aid CPUC staff's consideration of those issues, this document summarizes the issues and lists key questions for the parties to address in their written comments[3].

Relevant Language

SB 1078 states that the CPUC shall consider long-term costs associated with fixed-price electricity contracts from new generating facilities (399.14 (c)). In D. 03-06-071 and D. 04-16-015, the CPUC adopts and affirms a proxy plant methodology that uses a combined cycle gas turbine (CCGT) proxy plant for a baseload product and combustion turbine (CT) proxy plant for a peaking product (D. 03-06-071, p. 18-19; D. 04-16-015, p. 6). The CPUC finds general agreement that NYMEX natural-gas futures prices provide a reasonable proxy of forward market prices in the first six years of a long-term forecast horizon for which the futures contracts are traded. The Commission found no evidence that longer term fixed priced contracts for natural gas were actually traded. In the absence of such contracts, the Commission found that hedging costs provide a reasonable alternative that is more consistent with the statute than ignoring the costs associated with obtaining fixed prices for fuel on a long-term basis. D.04-06-015 did adopt a specific transaction hedging cost. Specifically, CPUC adopted PG&E's proposal to add one half the bid/ask spread, plus the collateral carrying cost, to the price of gas in the NYMEX years.

It appears that the pertinent language leaves some discretion to the CPUC in establishing the appropriate methodology for the natural-gas price forecast. The MPR methodology is to consider the long-term costs of delivering fixed price electricity over a 10-20 year term. However, it is not clear that this must automatically translate to assuming a fixed price for a natural-gas forward contract over the same term. It is also not clear that a firm signing a long-term

[3] 2005 MPR comments and reply comments are due July 29, 2005 and August 12, 2005, respectively

fixed price contract to deliver electricity would necessarily seek to immediately lock in natural-gas prices for the entire contract term. The low trading volume of NYMEX futures contracts for delivery beyond the next 12 months and the lack of futures or OTC data for 15-20 year fixed price natural-gas contracts suggest that a seller of a long-term electricity contract may not lock in natural-gas price for all its natural gas needs in a single transaction for the electricity contract's entire term.

Guiding Principles for 2005 MPR Gas Price Forecast

Parties cited portions of the above referenced legislation and CPUC decisions in support of various arguments regarding (a) the precise definition of the proxy plant for the MPR calculations; and (b) the implications for the MPR natural-gas price forecast. SCE argues that the methodology must apply specifically to forecasting the fixed forward price for natural gas that could be purchased by a proxy plant, were such a contract available in the market. Others argue that given such a product is not actively traded and readily available in the market, the forecast should reflect the price of natural gas that the proxy plant would expect to pay over the 10-20 year term.

Questions: Part 1

The Commission would like the parties to comment on each of the following proposed guiding principles for the 2005 MPR natural-gas price forecast to help resolve the issues raised at the workshop. In order to provide the Commission with the necessary record to fully evaluate the merits of divergent positions and proposals, please comment on the relevance or usefulness of each of the following principles.

1. Reflects Behavior of Market Participants

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

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2. Market Data Should Be Used To the Extent Possible

There is already general consensus among the parties that NYMEX natural-gas futures prices represent the best approximation of natural-gas forward market prices for the years in which the futures are traded. It has been suggested that additional forward market price data could be obtained from (a) surveys of market participants, or (b) the over-the-counter (OTC) market for longer terms. The methodology should either incorporate or at a minimum use this additional data for benchmarking, if such data can be readily obtained and used, and is both reliable and available for review and publication.

3. For Longer Term Contracts that Extend Beyond Available Market Data, Forecasts Should Exhibit A Clear Relationship to Fundamental Costs

At the June 20, 2005 workshop, there was extensive discussion regarding the difference between forward and expected spot prices, which are discussed in greater detail below. While there are multiple reasons that forward and expected spot prices may diverge in the short-term, unclear are the existence and implications of this diverging relationship for natural-gas prices in the long-term, beyond the horizon for which market-based forward prices are available. A number of parties suggested that it would be unreasonable for an existing supplier to sell a long-term natural-gas forward contract at prices substantially below the costs of production, storage and delivery of new supply.

4. Methodology Should Be Consistent With Evaluation of Other Products

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

5. Methodology Should be Verifiable Using Historical Data

Forecasts cannot be expected to be perfectly accurate. However, where possible, tests using historical data should produce relatively consistent results, without significant bias or error.

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6. Methodology Should be Consistent with Previous Regulatory Decisions

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

2004 MPR Gas Price Forecast Methodology

The Commission adopted a MPR natural-gas price forecast methodology in D. 04-16-015. That decision found general consensus that the NYMEX futures contracts, which trade up to 72 months (6 years) into the future, best approximate forward market prices for natural gas. Though some parties argued that the limited number of trades for the longer term contracts was a cause for concern, absent a specific proposal for determining an appropriate cut-off point, the Commission elected to use NYMEX data for the first six years of the natural-gas price forecast.

For years 7-20, the Commission adopted an approach advocated by CEERT, TURN and SDG&E. To estimate the annual escalation rate for years 7-20, this approach uses an average of natural-gas price forecasts that are based on economic cost fundamentals and produced by such entities as CERA, PIRA, Global Insight, the CEC, and EIA. As illustrated by Figure 1 below, applying the escalation rates implied by the average natural-gas price forecasts to the last year of NYMEX futures prices yields the annual prices for years 7-20, thus preempting the potential problem of a disconnect between the last year of NYMEX prices and the fundamental forecasts for the same year.

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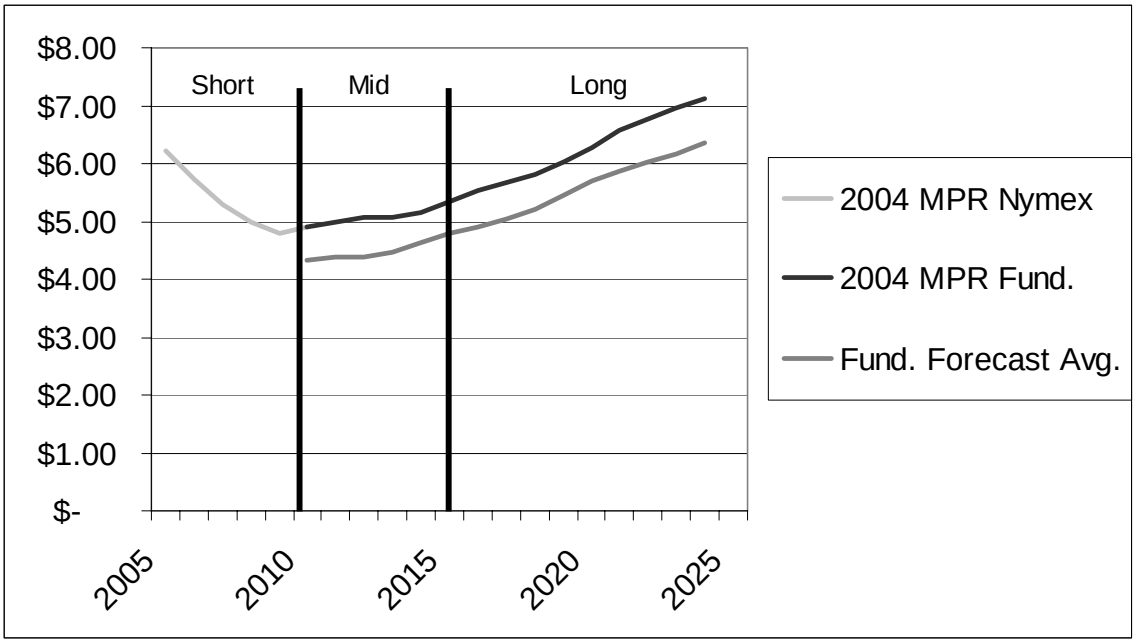
Figure 1: 2004 MPR Natural-Gas Price Forecast Methodology Using NYMEX and Fundamental Forecasts



Proposed Modifications

Participants in the June 20, 2005 workshop proposed modifications to the existing methodology for use in 2005. These proposals are listed below.

PG&E Proposal

PG&E has proposed using one or several independent commercial forecast services for forward market prices. Although each service provider may have a different methodology, they generally use a mix of NYMEX futures, OTC, and survey data to estimate forward prices beyond the NYMEX futures contracts. In addition, some providers use proprietary methods to forecast prices as far as 30 years into the future. Some utilities, including PG&E, use such services for mark-to-market and value-at-risk analysis of their portfolios. Other utilities use fundamental forecasts of expected spot prices. PG&E's proposal would utilize independent forward price forecasts. Just like private-sector fundamental price forecasts, the resulting forecasts proposed by PG&E would likely rely on proprietary/confidential data and methodologies, raising potential problems associated with the public dissemination of the results (though, through

aggregation, the CPUC has already addressed this vis-à-vis fundamental forecasts). How to appropriately share the cost of such services would also need to be determined.

SCE Proposal

Instead of relying on a fundamental forecast to predict future prices, SCE proposes a cost-of-carry (CCM) model to provide a current estimate of forward prices beyond the period for which the NYMEX futures contracts are traded. SCE argues that a price forecasts based on fundamentals will overstate natural gas costs because forward prices in the far future are generally lower than the expected spot prices in the near term. SCE argues that the difference between forward and expected spot prices can be explained by the convenience yield - a measure of the benefits of owning a commodity in the near term, as opposed to owning a contract for the same commodity to be delivered at a future date. SCE proposes (a) using a cost-of-carry model to estimates the convenience yield from available NYMEX data, and (b) applying the yield estimate to project a forward price curve beyond six years. SCE argues that this method provides a better indication of the hypothetical forward prices (as distinct from expected spot prices) that are relevant to the proxy plant. In addition, the model is transparent and easy to replicate and update. It would be possible to use this method in combination with PG&E's proposal. Figure 2 shows the result of using SCE's proposed CCM model compared to the other forecasts being considered.

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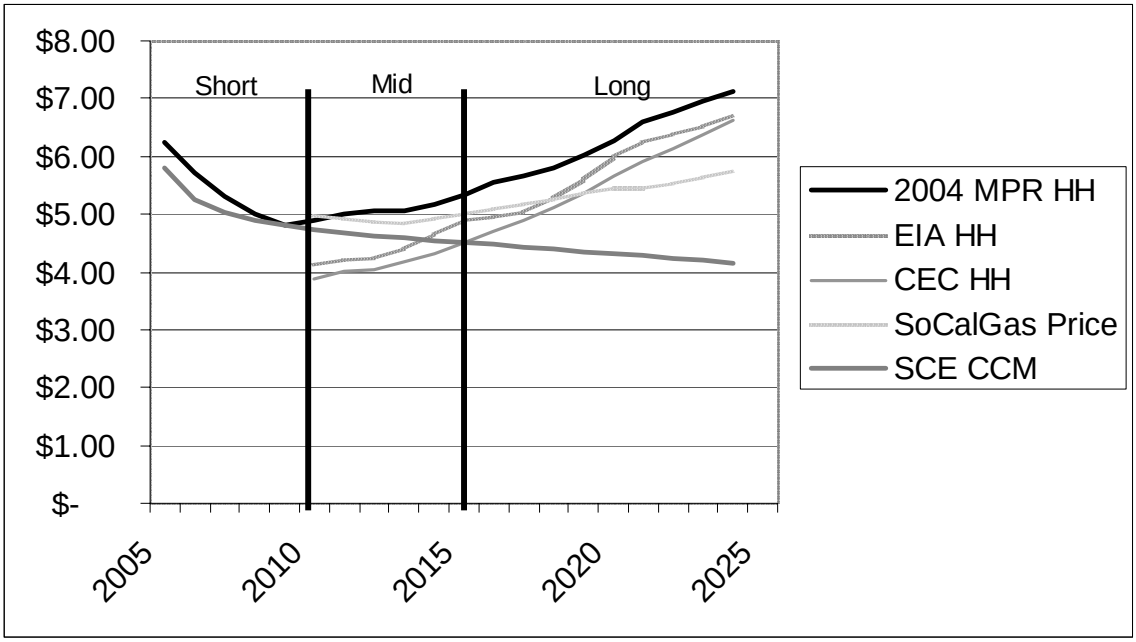
Figure 2: Cost-of-Carry Model Forecasts Significantly Lower Prices Over Long-Term



Comments on Alternatives

Table 1 below summarizes the alternatives. There continues to be general consensus that NYMEX or other available market data provides the best representation of market prices in the near- (1-6 years). There is also some agreement that some form of either market, OTC or survey data (if available and can be made public) might be used in the mid-term (6-10 years). However, the proposals differ markedly in methods used to estimate prices over the longer term (10-20 years), ranging from (a) incremental improvements to the existing method to (b) a different alternative of using market data to estimate forward prices over longer terms. As shown in Figure 2 above, the two bookend positions (a) and (b) can lead to dramatically different results, both in direction and absolute price levels. Using the COC model results in a substantially lower gas price forecast than the other Fundamental forecasts (EIA, SOCAL Gas and CEC).

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Table 1: Summary of Alternatives

Short-Term (Years 1-6)	Mid-Term (Years 7-10)	Long-Term (Years thereafter)
Market Data (NYMEX)	Market, OTC, Survey Data to Extent Available	Fundamental Forecast
		Cost-of-Carry Model

Questions: Part 2

To assist the Commission in evaluating the proposed alternatives, this section presents a number of questions for parties to address in their written comments organized as follows:

General Question

1. Provide a brief description of your proposal.

Short and Mid Term

As previously stated, there is a general concensus regarding the use of NYMEX futures data for the first six years of the forecast. Previously, some parties have raised concerns regarding the implications of limited trading activity for contracts over longer horizons.

Questions

2. If you are proposing an alternative method in the first six years, please describe the alternative in detail and provide supporting documentation and reasoning for the alternative.
3. If you propose not using NYMEX futures data for months with limited trading activity, please provide a specific recommendation for determining the point at which an alternative method should be used in favor of available NYMEX futures data.

Although this topic was not discussed in the workshops, the Commission has adopted a gas price forecasting methodology for the purpose of calculating the avoided costs of gas and electricity for DSM/CEE programs (R.04-04-025). In the adopted approach, the analysis period was divided into 3 periods: January 2004 – December 2005; January 2006 – October 2009; and, November 2009 and beyond.

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Published settlement prices for basis point swaps were used for initial period and the CEC's delivered price estimates for the period beyond 2009. The middle period estimate was developed using an econometric analysis of daily spot price data to determine that an unbiased estimate of the basis point differential between Henry Hub and each of the two California locations was not statistically different from zero. Hence, the avoided costs of gas in the DSM/CEE methodology relies only on the short term published NYMEX settlement data for the first two years and a half years of the forecast period.

4. The latest set of basis point swap settlement prices (June 30th, 2005) indicate that the average price difference over the period from July 2005 to December of 2007 is -.14 and -.46 $/MMBtu for PG&E City Gate and So Cal Gas, respectively. If you propose using the NYMEX futures data in your forecast, do you recommend using these adjustments for the 2005 through 2007 period in your forecast?
5. Please provide a recommendation for the basis point adjustment to be used during the remaining period (2008-2010) in which you are using NYMEX futures data.
6. Do you recommend additional transaction costs be added to the NYMEX futures data?

PG&E proposed using independent services such as Platts to supplement and extend the period for which forward price data is readily available. Such services utilize a mix of OTC data, surveys and in some cases proprietary models to provide forward price curves beyond the actively traded NYMEX contracts. Please provide comments based on the following assumptions: (1) issues regarding sharing the costs of purchasing these forecasts can be resolved, (2) the data may be made available only to CPUC staff due to pricing or confidentiality concerns, (3) the data provided is consistent with guiding principles for the MPR natural-gas price forecast methodology described above.

7. Describe and document any concerns you have regarding the use of such data for the period during which it can be obtained?
8. If you have any specific recommendations regarding when such data should or should not be used (i.e. for no more than 10 years, only if data

from 3 or more sources are available, etc), please describe and document those recommendations.

Questions: Part 3

To assist the Commission in evaluating the proposed alternatives, this section presents a number of questions for parties to address in their written comments organized as follows:

Long-Term

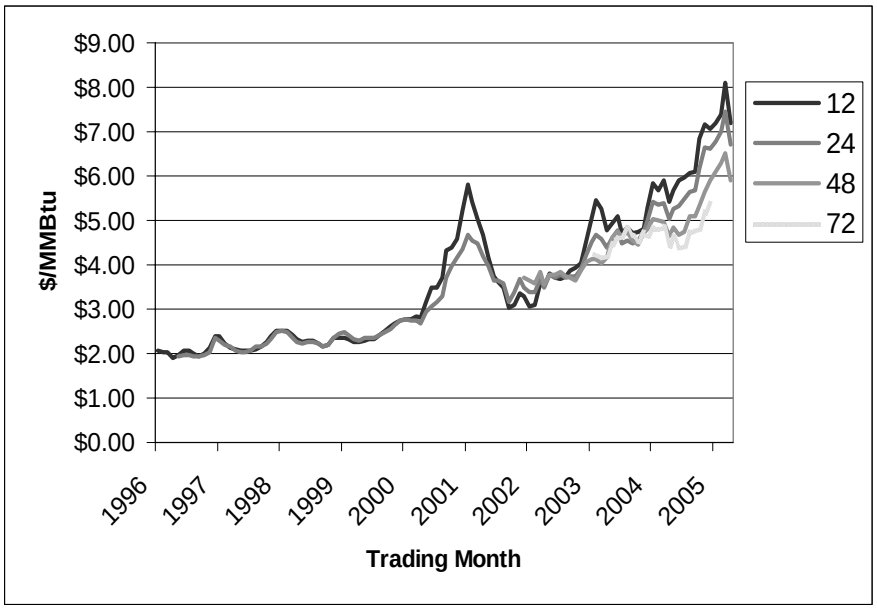
The proposals differ primarily in their use of either a "cost-of-carry" model or fundamental forecasts to estimate prices over the longer term beyond the horizon for which forward price data is available. Forward price curves on a given date for natural gas and other energy commodities sometimes exhibit backwardation - a downward time trend in the annual forward prices. SCE argues it is important to capture this trend in estimating forward prices, and its proposed CCM method yields a consistently downward trend over 20 years. Several parties found the CCM-based forecast counter-intuitive, given the historical increase in natural-gas prices, the current expectations for declining reserves and increasing production costs, and the increasing prices shown in all fundamental forecasts considered in this proceeding.

Additionally, one of the primary issues motivating the different proposals is the conceptual difference between a forward price and the expected spot price and the implications of the difference for the MPR natural-gas forecast methodology. SCE argues the forward prices that one can purchase at a given date are generally lower than the expected or actual realized spot price, as shown by the Nov-04 curve in Figure 4. The premise that forward prices differ from expected spot prices over the short-term is not difficult to accept; many reasons for such a difference have been postulated, including convenience yield, risk premium, net hedging positions, demand and inventory levels and the size and probability of potential shortages to name just a few. It is not immediately apparent, however, that these or any other reasons should cause forward and expected spot prices to diverge in a consistent or predictable manner. Neither is it clear that forward and expected spot prices should continue to diverge beyond the time horizon for which forward contracts are currently traded (6-10 years) or over the very long term (15-20 years). Evidence to support systematic differences between forward

and expected spot prices has been inconclusive, and some economists use the "efficient market" theory and arbitrage to argue that forward and expected spot prices are equivalent over all durations.

Figures 3 & 4 below display historical NYMEX data in two different ways, some of the following questions will refer to these figures.

Figure 3: Increasing Trend in NYMEX Futures Prices over Time



For the months listed on the horizontal axis, Figure 3 shows the average price over tha month for contracts 12, 24, 48 and 72 months in the future.[4] *In any given month, the price for longer term contracts tends to be lower than those for shorter term contracts. Over time, however, all contracts over all time horizons show a consistent upward trend.*

[4] In a trading month (e.g., January 1998), there are about 20 NYMEX futures prices for delivery in a future month (e.g., January 1999). The equally-weighted average of these 20 some daily prices is the trading month's average price for delivery in a future month.

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Figure 4: The Shape and Trend of NYMEX Futures Price Curves Have Changed Over Time

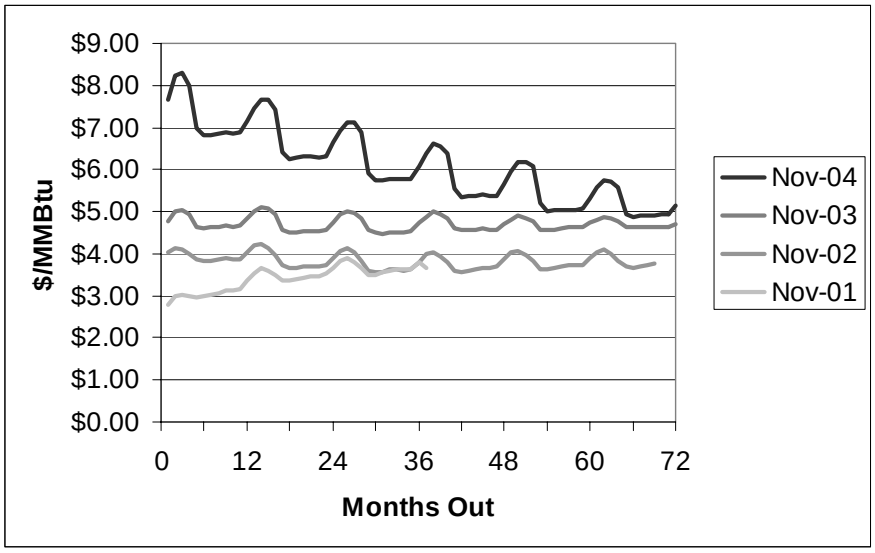

Figure 4 shows the NYMEX Futures Price Curves on the last trading day for November in 2001-2004. The forward curve displayed an upward trend in 2001, a relatively flat trend in 2002 and 2003, and a downward trend in 2004.

Questions Pertaining to Both Fundamental Forecasts and the Cost-of-Carry Model

9. Is the price trend resulting from the proposed methodology consistent with both historical trends and future expectations for gas prices? To the extent the trend differs, what is the explanation for the difference? Is that explanation supported by research, academic papers or industry experience? (See Figure 3)
10. Does the proposed methodology yield consistent and explainable results using data from a variety of time periods and market conditions or is it sensitive to when the forecast is being made? Can it be shown that a forecast made today will be similar or very different from the one made one month or one year ago? (See Figure 4)

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11. What types of tests, research or validation can be used to confirm that the proposed methodology is performing as should be expected? How can the proposed methodology be tested and validated using either historical price or forward contract data?
12. Other than in this proceeding, does your or any other company use your proposed method, as a general concept or as specifically proposed in this proceeding, to develop a long-term natural-gas price forecast for similar or other purposes (e.g. resource planning, risk management, procurement strategy, financial valuation).

Questions Specific to the Cost-of-Carry Model

13. Should one expect forward prices to differ from expected spot prices or a fundamental forecast over long (10-20 years) as well as short (1-5 year) terms? If so, is the price difference systematic, consistent and predictable over time? Is there consistent evidence or consensus that forward prices as predictors of spot prices are unbiased, biased high or biased low, on both a short-term and longer-term basis?
14. Can the factors leading to a difference between forward and expected spot prices be reliably measured and quantified? Is there a consensus regarding specific factors (e.g., convenience yield, risk premium, volatility) or methods (e.g., cost-of-carry vs. fundamental) that can be reliably used to develop robust forward price estimates?
15. For what reasons might one expect a counter-party to willingly sell a forward contract for natural gas 6-20 years out for less than the expected incremental cost of new production?
16. If forward prices are consistently biased either high or low, why does the opportunity for arbitrage not cause the convergence of the forward and expected spot prices? For example, if forward prices consistently underestimate expected spot prices, why don't speculators buy forward contracts, take delivery and make an expected profit, thus driving up the forward price?

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(END OF ATTACHMENT 1)

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ATTACHMENT 2

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(http://www.cpuc.ca.gov/PUBLISHED/RULINGS/47717.htm)

CERTIFICATE OF SERVICE

I certify that I have by mail, and by electronic mail, to the parties to which an electronic mail address has been provided, this day served a true copy of the original attached Administrative Law Judge's Ruling on Motion for Reconsideration on all parties of record in this proceeding or their attorneys of record.

Dated July 7, 2005, at San Francisco, California.

Janet V. Alviar

N O T I C E

Parties should notify the Process Office, Public Utilities Commission, 505 Van Ness Avenue, Room 2000, San Francisco, CA 94102, of any change of address to insure that they continue to receive documents. You must indicate the proceeding number on the service list on which your name appears.