UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company, Complainant, v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange, Respondents.	)	Docket No. EL00-95-031
Investigation of Practices of the California Independent System Operator and the California Power Exchange	)	Docket Nos. EL00-98-030 and EL00-98-033
California Independent System Operator Corporation	)	Docket Nos. RT01-85-000 and RT01-85-001
Investigation of Wholesale Rates of Public Utility Sellers of Energy and Ancillary Services in the Western Systems Coordinating Council	)	Docket Nos. EL01-68-000 and EL01-68-001

MOTION FOR CLARIFICATION AND
REQUEST FOR REHEARING OF THE
CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

The California Independent System Operator Corporation ("ISO")[1] respectfully submits this Motion for Clarification and Request for Rehearing of the Commission's "Order on Rehearing of Monitoring and Mitigation Plan for the California Wholesale Electric Market, Establishing West-Wide Mitigation, and Establishing Settlement Conference" issued on June 19, 2001, in the above-

---

1 Capitalized terms not otherwise defined herein are used in the sense given in the Master Definitions Supplement, Appendix A to the ISO Tariff.

identified dockets, 95 FERC ¶ 61,418 ("June 19 Order"), pursuant to section 313(a) of the Federal Power Act, 16 U.S.C. § 825l(a), and sections 212 and 713 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §§ 385.212 and 385.713.

I. INTRODUCTION AND SUMMARY

In the June 19 Order, the Commission took a number of much-needed actions to curtail the exercises of market power that have pervaded California wholesale electricity markets for the past year and have driven the price of wholesale electricity in the ISO markets to unjust and unreasonable levels. In response to rehearing petitions of prior orders filed by the ISO and others, the Commission extended price mitigation to spot markets in all hours, extended price mitigation throughout the Western interconnection, and precluded marketers from setting Market Clearing Prices. In addition, the Commission affirmed the must-sell and outage coordination requirements included in its April 26, 2001, order in these proceedings.

The ISO has repeatedly advocated that these and other measures are critical to return the rates for electricity and related services in the wholesale markets in California and throughout the West to just and reasonable levels. The measures adopted in the June 19 Order are needed also to ensure the availability of adequate supplies of Energy, which will permit the ISO to minimize System Emergencies and the potential for service curtailments (*i.e.*, blackouts) until California develops the new generation necessary to dependably serve

Demand. Accordingly, the ISO strongly supports the bulk of the measures adopted by the Commission in its June 19 Order.

There are, however, several aspects of the mitigation plan established in the June 19 Order that perpetuate the potential for unjust and unreasonable rates in the California markets and therefore require modification. In addition, the June 19 Order leaves a number of open questions relating to implementation of the mitigation plan established by the Commission that must be resolved. The ISO therefore urges the Commission to modify and clarify its June 19 Order with respect to the following issues:

- the applicability and appropriate form of price mitigation in the ISO's Ancillary Service markets;
- the September 30, 2002, termination date for mitigation measures;
- the payment of bids above mitigated Market Clearing Prices;
- the treatment of refunds for past over charges;
- the application of the 10% credit adder to prices paid in the ISO's markets;
- the level of the operations & maintenance ("O&M") adder to be used in calculation of a gas-fired unit's "proxy price;"
- the monitoring and enforcement of the West-wide mitigation requirements;
- the implementation of the must-offer requirement;
- the definition of spot transactions subject to price mitigation; and
- the allocation of charges for emission mitigation fees and fuel start up costs.

The ISO also notes that, as it is preparing this filing, it has only had a few weeks' experience in implementing the June 19 Order. The Commission's April 26 and June 19 Orders mandate significant changes in the structures and operation of the ISO's markets. Thus, there is a possibility that the changes mandated by the June 19 Order may have unforeseen consequences or that issues related to the ISO's implementation of the June 19 Order may arise that cannot yet be fully assessed. If additional issues of this nature arise, the ISO will bring them to the Commission's attention, either through a request for further clarification of the Commission's order or, if necessary, through a filing under Section 205 of the Federal Power Act with proposals to resolve any such issues.

II. BACKGROUND

The Commission has previously concluded in these dockets that the market structures and rules for wholesale sales of electric energy in California are "seriously flawed," and, in conjunction with the imbalance of supply and demand in California, have created the ability of suppliers of electricity in those markets to exercise market power and to charge unjust and unreasonable rates for energy.[2] On April 26, 2001, the Commission issued an order[3] adopting a prospective market monitoring and mitigation plan for real-time wholesale energy markets in California. The market monitoring and mitigation plan, which went into effect on May 29, 2001, included the following elements:

- expansion of the ISO's authority to coordinate and control planned generator outages;

---

[2] *See, e.g., San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange, et al.*, 93 FERC ¶ 61,294 at 61,998-99 (2000), *reh'g pending* ("December 15 Order").

[3] *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange, et al.*, 95 FERC ¶ 61,115 (2001) ("April 26 Order").

- a requirement that all Participating Generators, as well as all other generators located in California – including non-public utility generators but excepting hydroelectric units – that voluntarily make sales through the ISO's markets or use the ISO Controlled Grid, offer all of their available capacity in the ISO's real-time Energy market during all hours; and

- a price mitigation mechanism for all sellers bidding into the ISO's real-time Energy market during System Emergencies (*i.e.,* "periods of reserve deficiency," defined as beginning with a Stage 1 System Emergency) under which the Market Clearing Price will be set at a "proxy price," reflecting the highest marginal cost of all of the gas-fired units dispatched, as calculated by the ISO, pursuant to a formula set forth by the Commission. Under the April 26 Order, all sellers were permitted to submit bids greater than this proxy price, subject to refund and justification.

The April 26 Order failed to address a number of important issues, including price mitigation in non-emergency hours and "megawatt laundering." In addition, the April 26 Order was unclear regarding the appropriate price mitigation to be used in the ISO's Ancillary Service markets. The ISO requested guidance on price mitigation in Ancillary Service markets and other issues in its May 11, 2001 Compliance Filing and in status reports filed with the Commission on May 18 and May 25. On May 25, 2001, the ISO filed a motion for clarification and request for rehearing of the April 26 Order (the "May 25 Rehearing Request"), explaining, *inter alia*, the need for mitigation of the market power being exercised in all hours and in all wholesale markets and for a mechanism to address the problem of "megawatt laundering."

On May 25, 2001, the Commission issued an order confirming that the April 26 Order did not eliminate all price mitigation in the ISO's Ancillary Service markets and directing the ISO to replace the previous $150/MW breakpoint mechanism for Ancillary Service price mitigation with the methodology adopted in the April 26 Order.[4] In addition, in response to a motion filed by the Cities of Anaheim, Azusa, Banning, Colton, and Riverside California (collectively "Southern Cities") the Commission stated that it expects the ISO "to ensure the presence of a creditworthy buyer for all transactions made with generators who offer power in compliance with the must-offer requirement in the [April 26] Mitigation Plan."[5]

On June 19, 2001, the Commission issued its "Order on Rehearing of Monitoring and Mitigation Plan for the California Wholesale Electric Markets, Establishing West-Wide Mitigation, and Establishing Settlement Conference" in the above-captioned proceeding. The June 19 Order acted on the requests for rehearing of the April 26 Order and addressed a number of issues related to the May 25 Order. The June 19 Order substantially modified and expanded the market monitoring and mitigation plan adopted in the April 26 Order, establishing price mitigation in all hours and for all "spot markets" throughout the Western interconnection. Specifically, the June 19 Order:

- retained the price mitigation mechanism for all sellers bidding into the ISO's spot market during System Emergencies, but modified the formula for determining the "proxy price" used to determine the Market Clearing Price;

---

4 *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange, et al.*, 95 FERC ¶ 61,275 ("May 25 Order").

5 *Id.* at 61,972. On June 25, 2001, the ISO requested clarification or rehearing of aspects of the May 25 Order relating to Ancillary Service price mitigation and credit support requirement for Energy provided pursuant to the must-offer requirement. In an order issued on July 12, 2001, *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange, et al.*, 96 FERC ¶ 61,051 (2001) ("July 12 Order"), the Commission denied the ISO's request for rehearing of the May 25 Order but noted that certain issues raised in the ISO's request for rehearing of that order would more properly be raised in a request for rehearing of the June 19 Order.

- established a price mitigation mechanism for all sellers bidding into the ISO's spot market during non-System Emergency periods, under which the maximum Market Clearing Price for spot market sales during such hours will be eighty-five percent (85%) of the highest ISO hourly Market Clearing Price established during the hours when the last Stage 1 System Emergency (that was not also a Stage 2 or Stage 3 System Emergency) was in effect;

- mandated that all marketers be "price takers" and not be able to set the Market Clearing Price or be paid as-bid above the mitigated Market Clearing Price;[6]

- instructed bidders to remove emissions mitigation fees and start-up fuel costs from their bids into the ISO's markets and instead to invoice the ISO directly for these costs, which the ISO is to allocate to all Load in California that uses the ISO system;

- affirmed the requirement of the April 26 Order that all generators in California offer available generation for sale to the ISO's real-time Energy market;

- directed the ISO to add 10 percent to the Market Clearing Price paid to generators for all prospective sales in its markets to reflect "credit uncertainty;"

- found that ISO Tariff penalty provisions that might subject a unit forced out of service to a penalty in excess of the cost of replacement energy were unjust and unreasonable, and directed the ISO to modify its tariff so that the only penalty for having a unit forced out of service is the cost of replacement energy;

- directed the ISO to file on or before March 26, 2002, a report on market conditions including a list of new generating resources in the State of California and the status of long-term contracting efforts in reducing the reliance on the ISO's spot market; and

- established a September 30, 2002 sunset date for price mitigation in the wholesale electricity markets.

For purposes of clarity, in the remainder of this document the price paid in System Emergency hours using the "proxy price" formula will be referred to as the "Marginal Proxy Clearing Price" (this price is calculated on a ten minute

---

[6] Under the June 19 Order, sellers other than marketers will continue to have the opportunity to justify bids or prices above the maximum Market Clearing Prices.

interval basis); the hourly average of the six Marginal Proxy Clearing Prices within the hour will be referred to as the "Hourly Ex Post Price in a System Emergency"; and the maximum allowed Market Clearing Price in non-System Emergency hours will be referred to as the "Non-Emergency Clearing Price Limit."

III. SPECIFICATIONS OF ERROR

The ISO respectfully submits that the June 19 Order errs or should be clarified in the following respects:

A. Scope and Design of Price Mitigation

1. The order errs by setting forth a price mitigation mechanism for the ISO Ancillary Service Markets that would result in Ancillary Service prices above just and reasonable levels;
2. The order errs by establishing a sunset date for price mitigation on September 30, 2002 without substantial evidence that the market will operate effectively by that date;
3. The order errs by requiring "as-bid" payments to be made prior to a Commission determination that costs above mitigated prices are justified;
4. The order errs in failing to adequately address refunds for past overcharges by sellers;

B. Calculation of the Mitigated Prices

5. The order errs by imposing a 10 percent surcharge on prices in the ISO's spot markets;

6. The order errs by increasing the O&M component of the proxy price calculation from $2.00/MWh to $6.00/MWh;

C. Enforcement of West-wide mitigation Measures

7. The order errs in failing to provide for monitoring and enforcement of the West-wide mitigation requirements;

D. Compliance with the Must-Offer Requirement

8. The order should be clarified to provide for effective implementation of the must-offer requirement;

E. Other Issues

9. The order should be clarified as to the definition of spot transactions subject to price mitigation; and

10. The order errs in its requirements for the allocation of uplift charges.

IV. ARGUMENT

A. Scope and Design of Price Mitigation

1. The Price Mitigation Mechanism for the ISO Ancillary Service Markets Should Be Modified.

In the May 25 Order, the Commission clarified that its April 26 price mitigation plan applied to the ISO's Ancillary Services markets and provided guidance regarding the mechanism to be used in the ISO's Ancillary Service markets during System Emergency periods:

> With respect to calculating the market clearing price for Ancillary Services, we direct the ISO to use each relevant average hourly mitigated Imbalance Energy price. If the Ancillary Services markets clear below the average hourly mitigated Imbalance Energy price for that hour, then the ISO will pay the Ancillary Services clearing

> price for that market. If the Ancillary Services markets clear above the average hourly mitigated Imbalance Energy price, then the ISO will use that price to clear the market and will pay as-bid for all Ancillary Services that are needed above the mitigated price. Bids accepted above the mitigated price will be subject to refund and justification.

May 25 Order, 95 FERC at 61,971-72. The June 19 Order confirmed that the ISO was to continue to apply that Ancillary Service price mitigation mechanism during Emergency periods.[7] The Commission further held that:

> For spot market sales, both in the WSCC and in California, in all non-reserve deficiency hours (*i.e.*, when reserve levels in the ISO exceed 7%), we will adapt the use of these market clearing prices. Eighty-five percent (85%) of the highest ISO hourly market clearing price established during the hours when the last Stage 1 (not Stage 2 or 3) was in effect will, absent justification, serve as the maximum price for the subsequent period.

Id. at 7. The June 19 Order defines the ISO's "ancillary services and imbalance energy markets" as "spot markets." *Id.* at 2.

In its request for rehearing of the May 25 Order, the ISO requested: (1) confirmation that there is no basis on which suppliers of Ancillary Services can justify Ancillary Service capacity bids in excess of the mitigated Ancillary Service clearing price; (2) that the mitigation measures for the Ancillary Service markets be modified in order to establish an *ex ante* instead of an *ex post* price mitigation mechanism; and (3) clarification that the mitigation measures were applicable in all hours (rather than merely in System Emergency hours). In its

---

[7] "The ISO, CPUC, and PG&E further contend that mitigation should apply outside of the ISO's Imbalance Energy market and should include its Day-Ahead and Hour-Ahead markets for ancillary services and its congestion management market. The Commission's [May 25] order providing clarification and preliminary guidance addressed these issues." June 19 Order, slip op. at 21.

July 12 Order rejecting the ISO's request for rehearing of the May 25 Order, the Commission stated:

> With respect to the ISO's concerns with the Ancillary Services price mitigation mechanism, we note that the ISO essentially wants the Commission to apply the price mitigation plan adopted in the June 19 Order retroactively to this proceeding. That is an issue that is more appropriately addressed on rehearing of the June 19 Order and, accordingly, we reject the ISO's arguments concerning the Ancillary Services price mitigation mechanism.

July 12 Order, slip op. at 4. The ISO respectfully submits that the Commission misunderstood the nature of the ISO's concern. The ISO was not seeking simply a retroactive application of the Ancillary Service price mitigation established by the June 19 Order. Rather, it was requesting the application of a *different* price mitigation approach to Ancillary Services markets, for the reasons discussed below, and clarification that the Ancillary Service price mitigation measures provided for in the April 26 Order were applicable in all hours.

In implementing the June 19 Order, the ISO has applied mitigated prices as an *ex post* limit on the Market Clearing Price in the Ancillary Service markets during System Emergency Hours,[8] and mitigated prices as an *ex ante* limit on the Market Clearing Price in the Ancillary Service markets during Non-System Emergency hours. The ISO has permitted Ancillary Service bidders to be paid "as-bid" above these price limits, subject to justification and refund. Below, the ISO proposes a price mitigation approach that would be superior. To the extent

[8] In preparing this motion, the ISO identified an error in its July 10, 2001, filing of Tariff revisions to comply with the June 19 Order ("July 10 Compliance Filing"). In the July 10 Compliance Filing, the ISO indicated that the limit on Ancillary Service bids in Emergency hours would be the Marginal Proxy Clearing Price rather than the Hourly Ex Post Price in a System Emergency. This representation is incorrect. The ISO will file a correction to the Compliance Filing as soon as possible.

that the ISO has misinterpreted the Commission's orders and the mechanism for Ancillary Service price mitigation described below is, in fact, permitted by the June 19 Order, the ISO requests that the Commission clarify that fact and permit the ISO to revise its July 10, 2001, filing to comply with the June 19 Order accordingly. In the alternative, the ISO requests the Commission to grant rehearing of the June 19 Order and find that the mitigation measures for the Ancillary Service markets can be modified in order to establish an *ex ante* instead of an *ex post* price mitigation mechanism and that there is no basis on which suppliers of Ancillary Services can justify Ancillary Service capacity bids in excess of the mitigated Ancillary Service clearing price. In addition, the ISO still seeks clarification that the mitigation measures adopted in the April 26 order applied in all hours after May 29, 2001, as did the Ancillary Service price mitigation measures in effect prior to May 29, 2001.

a. Sellers Should Not Be Allowed To Seek or Obtain Payments for Ancillary Service Capacity Bids Above the Applicable Limit of Price Mitigation.

Bids into the ISO's Ancillary Service markets consist of two parts: a capacity bid and an Energy bid. There is no need to provide bidders the opportunity to seek payments above the applicable limit of price mitigation with regards to the capacity component of their Ancillary Services bids. This is because prices below the applicable limit of price mitigation are adequate to fully compensate sellers for Ancillary Service capacity costs; and because bidders may "cost justify" the Energy bids.

Bidders in the Spinning, Non-Spinning, and Replacement Reserve markets submit capacity bids indicating the price at which they are willing to make capacity available to satisfy Ancillary Service requirements in addition to Energy bids to cover their costs of producing Energy from that capacity. In the case of Spinning and Non-Spinning Reserve, if the bid is selected for the Ancillary Service, but the Energy associated with this capacity is not dispatched, then the bidder only receives the capacity payment. On the other hand, when the ISO dispatches Energy from the capacity selected for Spinning and Non-Spinning Reserve, the bidder is paid both the capacity payment and payment in accordance with its Energy bid. In the case of Replacement Reserve, the bidder receives either a capacity payment, in cases where the Energy associated with the capacity is not dispatched, or an Energy payment in cases where the Energy associated with the capacity is dispatched.

Under the June 19 Order, Ancillary Service capacity bids are capped at the average hourly mitigated Imbalance Energy price during System Emergencies, and at 85% of the highest average hourly mitigated Imbalance Energy price in the last Stage 1 Emergency (that was not also a Stage 2 or Stage 3 System Emergency) during Non-System Emergencies. Both these prices are intended to provide a seller a reasonable opportunity to recover its costs of producing Energy.

However, the cost of providing Ancillary Services, if the Energy associated with the capacity is not dispatched, is the opportunity cost associated with not selling Energy. For example, when the real-time Market Clearing Price is

$100/MWh, a unit with a production cost of $40/MWh that provides Ancillary Services and is not dispatched to provide Energy would have an opportunity cost of $60/MWh since $60/MWh is what the seller would have earned if it sold the Energy. Since no unit has a production cost of $0/MWh, this opportunity cost will always be less than the applicable real-time Energy price that unit would earn. (In a competitive environment, resources with relatively high production costs – *i.e.* a low opportunity cost – will tend to provide Ancillary Services.) If all the Energy associated with an Ancillary Service bid is dispatched, there is no opportunity cost at all.[9] Thus, the price mitigation mechanism applicable to the sale of Ancillary Services capacity should reflect the difference between the resource's cost of producing Energy and the price of Energy.

Accordingly, the price limits adopted in the June 19 Order overstate the cost of the capacity component of Ancillary Service bids. Since this is true, it is inappropriate to allow sellers to seek to justify payments above the price limits for the capacity component of Ancillary Service bids.

Furthermore, the Energy component of Ancillary Services bids is subject to the same price mitigation as all other forms of Imbalance Energy, with the same opportunity to justify bids at whatever level is necessary to ensure recovery of the supplier's marginal costs. Thus, any attempt to "cost justify" Ancillary Service capacity bids above price limits based on a unit's costs of production

[9] This is not the case for Replacement Reserve capacity, where as explained earlier, dispatched Replacement Reserve capacity receives only the Energy price and not a capacity payment.

when dispatched, only would provide the opportunity for double-recovery of those costs.

In sum, sellers should not be allowed to seek or obtain payments for Ancillary Service capacity bids above the applicable mitigated price limit. The approach recommended by the ISO for Ancillary Service price mitigation described below is consistent with this view.

b. An *Ex Ante* Approach To Ancillary Services Price Mitigation Is Superior

Under the price mitigation regime adopted in the June 19 Order, the mitigated price limit applicable during System Emergency hours will not be determined until after the fact. The ISO's Ancillary Service markets, however, operate on a Day-Ahead and Hour-Ahead basis. Therefore, bidders into those markets for System Emergency hours will not know the applicable limit before they bid into the ISO's Ancillary Service markets. Thus the Commission has established a price mitigation regime for Ancillary Services that is inconsistent with the Commission's conclusion, "[t]o the extent possible, our price mitigation should have clear rules, *should set prices before they are charged* and should not subject prices to change or adjustment after financial settlement of the day's transactions." June 19 Order, slip op. at 6 (emphasis added).

To provide for an *ex ante* approach to Ancillary Service capacity price mitigation, the ISO recommends that prices in the Ancillary Service capacity markets in all hours including System Emergency hours be limited to 85% of the Hourly Ex Post Price in a System Emergency established during the most recent Stage 1 period (that was not also a Stage 2 or Stage 3 System Emergency) just prior to the deadline for closure of the applicable market (*i.e.*, closure of the Day-Ahead market for a Day-Ahead bid, and closure of the Hour-Ahead market for an Hour-Ahead bid).[10] This approach essentially extends the Ancillary Service price mitigation provided in the June 19 Order for Non-System Emergency hours to all hours. Furthermore, consistent with the discussion in the section above, sellers would not have an opportunity to seek or obtain payments above the Non-Emergency Clearing Price Limit.

The approach recommended by the ISO provides limits for Ancillary Service capacity bids more in keeping with just and reasonable rates (although the limit may still be above the opportunity cost of the marginal unit in many hours), than the approach set forth in the June 19 Order. Moreover, unlike a fixed hard cap, the approach reasonably allows for the limitation on Ancillary Service capacity prices to adjust to changes in market conditions.

As noted above, the ISO has not had an opportunity to fully assess the impact of the modified market structure established by the June 19 Orders on the ISO's Ancillary Service markets. As the Commission has directed, the ISO will monitor those markets and, if the continued potential for anti-competitive bidding is detected, will propose additional measures to address such behavior.

---

[10] The ISO previously proposed an approach to mitigate Ancillary Service prices in its Market Stabilization Plan as part of a proposed Day-Ahead unit commitment market. Under the ISO's Market Stabilization Plan proposal, Ancillary Services and Day-Ahead Energy would be procured simultaneously and Ancillary Service capacity prices would reflect the maximum differential between real-time Energy prices and the actual production costs of generation. Adopting this approach under the price stabilization plan established by the Commission for the California wholesale electricity markets is not possible because the ISO does not currently have a Day-Ahead Energy market from which to calculate, *ex-ante*, a unit's opportunity cost for providing Ancillary Services. When a Day-Ahead Energy market is established, such a mitigation plan may be appropriate.

c. Ancillary Service Price Mitigation Measures Should Be Applied in All Hours as of May 29, 2001, the Effective Date of the April 26 Order.

Consistent with the Commission's directive in the July 12 Order that the issue of whether "to apply the price mitigation plan adopted in the June 19 Order [*i.e.*, price mitigation in all hours] retroactively to this proceeding . . . is an issue that is more appropriately addressed on rehearing of the June 19 Order," (June 19 Order, slip op. at 4) the ISO renews its request that the Commission clarify that price mitigation in the ISO's Ancillary Service markets in accordance with the April 26 Order has been applicable in all hours, rather than merely in System Emergency hours.

The May 25 Order, while clarifying that the price mitigation measures adopted in the April 26 Order applied to Ancillary Service capacity bids, did not address whether the measures applied in all hours including non-System Emergency hours.

The Commission's previous Ancillary Service price mitigation mechanism – a $150/MW breakpoint mechanism – which was effective from January 1, 2001 through May 28, 2001, applied in all hours. As of the effective date of the June 19 Order – which extended price mitigation in all California and Western Systems Coordinating Council spot markets to all hours – there is no doubt that price mitigation in the ISO's Ancillary Service markets will be applicable in all hours. The Commission should clarify that the April 26 Order also established Ancillary Service price mitigation in all hours using the methodology set forth in the May 25 Order.

Anything else would be inconsistent with the Commission's finding that mitigation of Energy and Ancillary Service prices during all hours is necessary and appropriate in order to "protect customers." June 19 Order, slip op. at 5. If the Commission does not provide such clarification, the ISO believes that the Commission's subsequent findings concerning the need for price mitigation in the ISO spot markets in all hours require that the Commission grant rehearing on this issue and hold that the Ancillary Service price mitigation established by the May 25 Order applies in all hours as of May 29, 2001.

2. Pursuant to the Federal Power Act, the Commission Must Condition the Sunset Date of September 30, 2002 for Its Price Mitigation Measures on a Finding that Market Conditions Will Result In Just and Reasonable Rates.

The automatic September 2002 sunset date specified in the June 19 Order for price mitigation is contrary to the Commission's responsibilities under the Federal Power Act and the record in the case.

In the April 26 Order, the Commission provided that price mitigation measures adopted in the order were to be in effect for one year only, until May 2002. April 26 Order, 95 FERC at 61,364. On May 25, 2001, the ISO and others sought rehearing of the May 2002 sunset date. The ISO stressed that the one year duration for the mitigation plan is arbitrary and capricious, and could not be justified by the record.[11] In its June 19 Order, the Commission responded to arguments on the sunset date of the ISO and other parties. June 19 Order, slip op. at 39-40. The Commission extended the effective period of the mitigation

---

[11] ISO's May 25, 2001 Motion for Clarification and Request for Rehearing at 84.

measures to Fall 2002. *Id.* In addition, the Commission required the ISO to file, on or before March 26, 2002, a report on market conditions that addresses among other things: (1) a list of all new generating resources (including nameplate capacity) that the State of California has announced this year would be on line by summer 2002 and which of these facilities are actually on line; and (2) the continued progress in executing long-term contracts and reducing reliance on the spot market. *Id.* The Commission also extended its requirement for quarterly reports on progress towards implementing Demand response programs and new Generation. *Id.*

The requirement for a report by the ISO on key market parameters before March 26, 2002, and quarterly reports on progress towards implementing Demand response programs and new Generation will provide valuable information. However, the June 19 Order fails to consider or establish the criteria for concluding that a competitive market exists, and to connect the requirement for filing critical data regarding competitiveness of the market with the need for an affirmative finding by the Commission, prior to lifting price mitigation measures, that conditions are such that fair and reasonable prices will be assured. This failure is contrary to the Commission's responsibilities under the Federal Power Act.

To correct this deficiency, the ISO respectfully requests the Commission modify the June 19 Order: (1) to provide that the Commission's mitigation measures will remain in place until such time as the Commission's review of the California and Western markets demonstrates that a workably competitive environment exists; (2) to provide that the Commission will initiate a proceeding to determine the explicit and objective criteria necessary for determining when competitive market conditions exist; and (3) to provide that the Commission will initiate, subsequent to the submission of the ISO's March 26, 2002 Report, a proceeding to determine whether competitive market conditions exist in the California and Western markets.

While the Commission may adopt market-based methodologies to achieve just and reasonable rates, the Commission may not abdicate to the market its responsibility to set just and reasonable rates.[12] The Commission itself, in the June 19 Order, recognized that, in adopting market based rates, the Commission must:

> (1) provide a clear and reasoned analysis for the need for market-based pricing to promote the statutory objectives of the FPA; (2) support its decision with substantial evidence; and (3) assure that the resultant market-based rate falls within a 'zone of reasonableness.'[13]

When it terminates the price mitigation plan, the Commission will return to sole reliance on the market to ensure just and reasonable rates. The Commission may only do so, however, based on a demonstration that the market will produce such lawful rates.

There is no evidence in the record to demonstrate that the market will produce just and reasonable rates by Fall of 2002. To the contrary, in a series of

---

12 *See* the ISO Motion for Clarification and Request for Rehearing at 12-16; *citing Elizabethtown Gas Company v. FERC*, 10 F.3d 866, 875 (D.C. Cir. 1993*); Federal Power Com'n v. Texaco*, 417 U.S. 380 at 391-92 (1974).

13 June 19 Order, slip op. at 29.

orders, the Commission has recognized that "as a result of the seriously flawed electric market structure and rules for wholesale sales of electric energy in California, unjust and unreasonable rates were charged, and could continue to be charged during certain times and under certain conditions, unless certain targeted remedies were implemented." June 19 Order, slip op. at 25. In the June 19 Order, the Commission listed as a basis for putting into place price mitigation in non-Emergency hours, comments received and prices recently observed in California even in hours where there is no reserve deficiency. *Id*. at 4. The Commission specifically cited a recent particularly egregious and emblematic instance of abuse of market power, a $3,880/MWh bid by Duke Energy that resulted in total revenues to Duke Energy of $11 million. *Id*. at 37. The Commission admitted that,

> [w]hile progress has been made in correcting market dysfunctions, the dysfunctions will not be fully corrected until additional load is moved from the spot market to longer-term contracts (a mixed portfolio of supply contracts) and the basic structural defect of inadequate supply in the West is corrected.

Id. at 4. Having found that market power exists, the Commission cannot rely upon speculation to support a return to sole reliance on market-based rates.[14]

In the April 26 Order the Commission relied, for its determination that a one year effective period for the price mitigation was appropriate, on its requirement for Demand response programs to be in place and the Governor's projection that new Generation will be online. April 26 Order, 95 FERC at 61,354. While Californians have engaged in substantial conservation efforts, and

[14] *See Electric Consumers Resource Council v. FERC*, 747 F.2d 1511 (1984).

progress is being made towards adding new generation in California and the West, there has been no demonstration that conservation and additional generation will be sufficient by Fall 2002 to assure a fully competitive market. In fact, a definitive sunset date for price mitigation could discourage generation additions, since generators would know that after Fall 2002 they could return to a regime of market power abuse, if they defer currently planned generation additions.

While it is possible that, in the end, price responsive demand, long-term contracting, and new generation will enable the return to "just and reasonable" rates through a fully market-based regime, the Commission may not speculate on this result. Instead, the Commission must the determine the criteria by which to evaluate whether a competitive market will be effective to provide for "just and reasonable" rates, and must determine based on substantial evidence that these criteria have been met *before* the Commission’s price mitigation measures terminate.

In order to provide an adequate record to make a meaningful determination on the on-going need for price mitigation measures in Summer 2002, the Commission should begin by initiating a proceeding to determine the criteria to be applied in determining whether adequate competitive market conditions exist.

As Commissioner Massey has recognized, the Commission's traditional market power analysis (*i.e.*, the “hub and spoke” analysis) is in need of updating and refinement.[15] He noted that a number of factors need to be addressed including: regional market competitiveness, adequate generation capacity, interconnection policies, the ability to hedge, congestion management, demand responsiveness, *ex ante* price mitigation, and RTO participation. *Id.* The ISO believes that, among other factors, it is appropriate to measure and evaluate capacity margins, the number of suppliers in any given market, and the adequacy of gas transport and electric transmission infrastructure.

Once clear criteria have been established, the ISO can assess and address them in its March 26, 2002 Report. The report could then provide the information needed by the Commission to make an adequately supported determination on the continuing need for price mitigation measures.

In sum, the ISO is again concerned with the Commission's adherence to an arbitrary termination date for its prescribed price mitigation measures. The record is devoid of substantial evidence that by Fall 2002, the market dysfunctions that provide the basis for the price mitigation measures adopted in the December 15, April 26, and June 19 Orders will no longer exist.

3. Commission Review of the Justification of Bids Above the Mitigated Prices Should be Required Before As-Bid Payments Above the Mitigated Prices Are Made.

The ISO seeks modification of the Commission's determination that suppliers will be paid as-bid subject to review and refund above the mitigated price limits. Instead, Commission review of and determination on a seller's justification for "as-bid" prices should precede an obligation on the part of a buyer

---

[15] *See, e.g.*, Commissioner Massey's recent dissents in *San Manuel Power Co. LLC*, 96 FERC ¶ 61,089 (2001) and *Duke Energy Mohave, LLC*, 95 FERC ¶ 61,256 (2001).

to pay such prices and should be undertaken in an open and transparent manner. This approach is justified since the wholesale price mitigation measures adopted in the June 19 Order afford sellers a reasonable opportunity to recover their costs. This approach is also appropriate in light of the pervasive market abuses by sellers that have been documented, and to provide incentives for sellers to cooperate with Commission review of their as-bid justification.

The mitigated prices calculated in accordance with the June 19 Order afford sellers a reasonable opportunity to recover their costs. During System Emergencies, prices are calculated based the actual heat rate of the highest priced unit dispatched by the ISO using fair assumptions about gas prices and, if the ISO's request for modification on O&M costs is granted, O&M costs.[16] Sellers are not at risk for emission mitigation costs and start-up fuel costs as these are to be paid as incurred, for Energy provided in accordance with the must-offer obligation or ISO dispatch instructions. *Id*. at 31-33. The Commission itself stated in the June 19 Order, in dismissing arguments by sellers that the Marginal Proxy Clearing Price should include components for opportunity costs, scarcity rents, and recovery of fixed costs:

> The Commission, in this order, has sought to provide prices that emulate closely those that would result in a competitive market and that provide generators with a reasonable opportunity to recover their costs. . . . The Commission's mitigation plan uses available data to develop reasonable marginal costs for each generator and to permit reasonable recovery of legitimate costs. If sellers do not believe that these prices sufficiently cover their costs, they can file for cost-of-service rates covering all of their generating units in the WSCC for the duration of the mitigation plan.

[16] If the ISO's request for modification of O&M costs is not granted the O&M assumption will be overly generous.

Id. at 39.

Given that the mitigated prices calculated in accordance with the June 19 Order provide sellers a reasonable opportunity to recover their costs, such prices are presumptively compensatory and thus reasonable from the perspective of sellers. Conversely, prices charged above mitigated levels, at least in the first instance, are presumptively excessive, unjust and unreasonable. This conclusion flows logically from the manner in which the June 19 mitigation plan is intended to operate. Thus, to the extent sellers are nonetheless allowed to seek payments above mitigated prices, they should have the burden of demonstrating that the additional amounts are justified prior to payment for such amounts.[17] In addition, the determination of adequate justification for additional payments should be made in an open and transparent manner. At a minimum, the information submitted by sellers to justify as-bid payments should be made available, in addition to the ISO, to all other entities with an interest in ensuring that sellers are not overpaid.

The recent experience in the market further supports a transparent Commission determination regarding payments above mitigated prices before such payments are made. Abuse of market power has been pervasive and amply documented. Assessments of the Department of Market Analysis ("DMA") indicate that 30 percent of the Wholesale Energy costs over the last year can be

---

[17] In fact, given that mitigated prices calculated in accordance with the June 19 Order afford sellers a reasonable opportunity to recover their costs, and that sellers always have the option to return to cost-based rates if the mitigated prices are inadequate, allowing sellers to seek "as-bid" payments at all could be viewed as unnecessary and redundant (except perhaps in the case of out-of-sequence calls).

attributed to the exercise of market power; and that prices exceeded the competitive market benchmark in all hours under a variety of conditions.[18] DMA has documented that, to date, consumers have paid billions of dollars above just and reasonable prices. In this context, a Commission determination that prices above the mitigated prices are justified should precede any payment of such prices.

Further, requiring a Commission determination that costs above the mitigated prices are justified will provide incentives to sellers to cooperate fully in Commission review of the justification they submit. For example, sellers would have an incentive to submit timely justification and to provide sufficient information to allow the Commission to adequately assess bids. The June 19 Order notes at least one instance in which a seller not only submitted an exorbitant bid but failed to report the transaction in its quarterly report as required. June 19 Order, slip op. at 41. Such abuses will be significantly reduced if payments above the mitigated prices are made only after a finding by the Commission that they are justified.

In sum, the ISO seeks modification of the June 19 Order to provide for Commission review of and determination on a seller's justification for as-bid prices pursuant to a transparent and open process before payment of such prices by the buyer. This approach is justified in light of the fully compensatory new price mitigation approach and pervasive market abuses. To the extent the Commission declines to modify the June 19 Order, the ISO seeks rehearing on this matter.

[18] ISO's May 25, 2001 Motion for Clarification and Request for Rehearing at 21 n. 23.

4. The Order Errs in Failing To Adequately Address Refunds for Past Overcharges by Sellers.

The June 19 Order provides that "refund (offset) issues related to past periods are to be addressed in a settlement conference." June 19 Order at 52. As stated in a recent motion for refunds by the California Parties, including the ISO, the Commission should promptly issue a refund order based on the Commission's finding and the extensive record in this proceeding developed over the past ten months. Rather than restate its argument on this issue herein, the ISO refers the Commission to the July 12 Motion for Refunds of the California Parties and incorporates those positions by reference.

B. Calculation of the Mitigated Prices

1. It Is Unjust and Unreasonable To Impose a Ten Percent Credit Adder to Prices in the ISO's Spot Markets.

In the June 19 Order, the Commission instructed the ISO "to add 10 percent to the market clearing price paid to generators for all prospective sales in its markets to reflect credit uncertainty." June 19 Order, slip op. at 35. Due to various Commission orders requiring that the ISO ensure a "creditworthy" purchaser or counter-party for all transactions in the ISO's markets, however, there is no basis for such a surcharge.

To date the Commission has not modified its "creditworthiness" orders and the ISO has acted in accordance with the Commission's directives. The ISO has entered into arrangements with the California Department of Water Resources ("CDWR") that ensure that there is a creditworthy purchaser or counter-party for all prospective ISO Market transactions and real-time dispatch instructions issued to maintain the balance of supply and demand on the ISO Controlled Grid.[19] Sellers are thus fully protected, and unless the Commission modifies its creditworthiness orders, there can be no justification for an additional 10 percent adder to ISO Market Clearing Prices to reflect "credit uncertainty."

The rationale for the creditworthiness orders is that the ISO must ensure that suppliers have the equivalent of the assurances of payment that they would have but for the current crisis and financial distress of the California investor-owned utilities. The ten percent adder appears to be predicated on a diametrically opposed assumption: that the credit risk has not bee addressed.[20]

Requiring the ISO to obtain the support of a creditworthy party for ISO Market transactions and real-time dispatch instructions and then *also* mandating a "credit risk" adder inappropriately compensates sellers through the ISO's markets for a credit risk that does not exist. At least two Commissioners concurring with the June 19 Order acknowledge this disparity: Commissioner Breathitt, in her concurring opinion, notes that "the imposition of such a credit surcharge" is inconsistent with the implementation of "the Commission's creditworthiness standards." June 19 Order, 95 FERC ¶ 61,418, Breathitt *conc.*,

---

[19] The nature of the ISO's arrangements with CDWR have been described in various filings with the Commission – most recently in the ISO's Motion for Leave to Respond One Day Out-of-Time and Answer of the California Independent System Operator Corporation to Motions to Intervene, Comments, Motion for Leave to File Protest Out-of-Time, Conditional Protest, and Protests of the May 11, 2001, Compliance Filing, filed in Docket No. ER01-889-005 on June 19, 2001, and incorporated herein by reference.

[20] The June 19 Order eliminates any doubt that the 10 percent adder is intended to address only prospective credit risks when it states that "[t]he adder is not instituted to compensate generators for past unpaid bills." June 19 Order, slip op. at 35.

slip op. at 1.[21] Similarly, Commissioner Massey, in his concurring opinion states "I am concerned that the adder may diminish the ISO's enforcement of those [creditworthiness] requirements." June 19 Order, 95 FERC ¶ 61,418, Massey *conc.*, slip op. at 2.

The ISO agrees with these Commissioners that the requirements of the Commission's creditworthiness orders cannot be reconciled with the 10 percent credit risk adder imposed by the June 19 Order. If the ISO is required to comply with both, then it will be forced to pass on excessive costs to California end-use consumers to compensate suppliers for a credit risk which has already been mitigated by the Commission's creditworthiness orders. Such a result is inconsistent with the requirements of the Federal Power Act that all rates passed on to end-use consumers must be "just and reasonable" and represents an abuse of the Commission's discretion. For these reasons, the Commission must grant rehearing of the June 19 Order and eliminate the requirement that the ISO add 10 percent to Market Clearing Prices in its markets to reflect credit uncertainty.

The portion of the June 19 Order discussing the 10 percent adder also includes the following observation: "We also note that there is a longer payment lag in the ISO spot markets of approximately 75 days that does not generally

---

21 Commissioner Breathitt also "call[s] upon the ISO immediately to implement our orders regarding creditworthiness." June 19 Order, Breathitt conc., slip op at 1-2. As the ISO has indicated in numerous filings with the Commission, the ISO has complied with the Commission's orders relating to creditworthiness, notwithstanding the ISO's objections as to the legal basis for those orders. *See* May 25, 2001, Answer of the California Independent System Operator Corporation to Motion for Clarification of the Cities of Anaheim, Azusa, Banning, Colton and Riverside, California, filed in Docket Nos. EL00-95-000, *et al.* at 4-5; June 7, 2001, Answer of the California Independent System Operator Corporation in Opposition to Expedited Motion for Enforcement Action, filed in Docket Nos. ER01-889-003, *et al.* at 4.

exist in the Western bilateral spot markets." *Id*. at 35. This observation suggests that the settlement period in the ISO's markets is a factor that supports the 10 percent credit adder.

Tariff provisions implementing the current ISO Payments Calendar – which provide for payments to suppliers within an average of 73 calendar days, were approved by the Commission in Amendment No. 25 to the ISO Tariff.[22] The current calendar superseded the prior ISO Payments Calendar approved by the Commission, under which it took an average of 93 calendar days for suppliers to receive payment.[23] The Commission has never held that the time needed to process the complex settlements in the ISO's markets represents an unjust or unreasonable condition of sales in those markets, exposing suppliers to undue credit risks. In order for the Commission to make such a finding now, it would have to initiate an investigation *of this issue* under Section 206 of the Federal Power Act and determine that the ISO's previously-approved settlements provisions are now unjust and unreasonable. Accordingly, the ISO payment calendar cannot be a factor to support the 10 percent credit risk adder.

2. The Increase in the Operations and Maintenance Adder To the Proxy Price of Gas-Fired Units From \$2/MWh To \$6/MWh Is Arbitrary and Unsupported.

In the April 26 Order, the Commission added \$2.00 to the marginal cost price for each generator to represent O&M expense. June 19 Order, slip op. at 32-33. The Modesto Irrigation District ("MID") protested the \$2.00/MWh figure.

---

[22] *California Independent System Operator Corporation*, 90 FERC ¶ 61,316 at 62,050 (2000).

[23] *See id*. at 62,049.

Id. In the June 19 Order, the Commission stated it was "cognizant of the concerns raised by MID that the O&M adder may be lower than actual O&M expenses; therefore, we will increase the O&M adder from $2/MWh to $6/MWh." *Id*. at 32.

The increase in the O&M adder from $2/MWh to $6/MWh is inadequately supported and hence arbitrary and capricious. The Commission justified the increase of the O&M adder to six dollars based on a seventeen year average of actual non-fuel O&M expenses for oil and gas-fired steam plants, using data from a Department of Energy ("DOE") publication, Oil and Gas Steam Plant Operations and Maintenance Costs, 1981-1997. The Commission argued that the California market primarily consists of older oil and gas-fired steam plants and that accordingly "using a long-term average of actual O&M expenses for the same kind of units currently in the California market should permit generators in the California market full recovery of all non-fuel expenses." *Id*. at 33.

It is true that using a high figure for O&M expenses should permit generators in the California market full recovery for non-fuel expenses. However, using an unduly high figure exposes customers to rates that are not just and reasonable. Thus, merely seeking a figure that guarantees generators full recovery of non-fuel expenses is an inappropriate criteria to determine O&M expenses. Instead, it is important that the O&M figure be accurate since it could significantly affect costs to electricity consumers in the West.

The June 19 Order does not contain an adequate analysis to demonstrate that the six dollar figure is in fact accurate. The DOE information relied on appears to be close to five years old and there is no detailed analysis of the relevancy of the dated DOE data to the current California fleet. It is instructive that, of the many generators that are parties to this proceeding, only MID indicated that the two dollar O&M assumption in the April 26 Order was too low. In fact, based on available information, the ISO believes that an O&M adder of $6/MWh is too high and if applied in the determination of the Marginal Proxy Clearing Price will produce unjust and unreasonable rates. The $2/MWh rate as specified in the April 26 Order is more consistent with actual data.

The capacity-weighted average variable O&M rate for 41 current or former Reliability Must Run Generating Units in California is $1.5527/MWh.[24] The individual unit costs that form the basis for this number were agreed to in the "black box" individual generator rate settlements as part of the April 2, 1999 global settlement of many RMR issues. These units represent over 10,000 MW of in-state gas-fired generating capacity.

The $1.5527/MWh figure excludes costs from five older low capacity-factor units (the Oakland and Humboldt combustion turbines) that exceed $30/MWh. These rates were high, however, because the units ran so infrequently that the number of MWh over which the operating and maintenance costs were spread was small.

Accordingly, the Commission should reverse its $4/MWh increase to the O&M variable of the proxy price formula and restore the $2/MWh rate from the

[24] *See* Attachment A to this filing.

April 26 Order. Failure to take this action will result in significant harm to consumers by overstating the O&M variable of the proxy price.

C. The Commission Should Adopt Effective Monitoring and Enforcement Measures to Enforce the West-wide Mitigation Measures.

The West-wide market mitigation enacted by the Commission in the June 19 Order represents a significant step in limiting the exercise of market power and providing effective price relief for electricity consumers during the current crisis in the Western electricity market. The combination of: (1) price mitigation for all spot transactions in the WSCC region, including bilateral trades as well as sales into formal markets, and (2) a West-wide must-offer requirement to prevent the physical withholding of available capacity, is necessary to eliminate all opportunities for suppliers to circumvent partial price mitigation by withholding supply for sale in spot bilateral transactions at exorbitant prices. Because these measures are absolutely critical to ensuring just and reasonable wholesale electric rates in the West, the Commission must specify effective monitoring and enforcement measures. Failure to adopt these measures will potentially jeopardize the effectiveness of the entire mitigation approach.

There are two aspects of market participant behavior that require monitoring for compliance with the Order: the must-offer requirement, and price mitigation of spot transactions. Each of these requires a different monitoring approach.

To monitor compliance with the must-offer requirement, the Commission should require all non-hydroelectric generators in the West to file weekly reports with the Commission. These reports should identify all non-hydroelectric generating resources and their nameplate capacities, and should report for each operating hour of the week each resource's actual available capacity (*i.e.*, total capacity capable of providing energy), explanations for any differences between nameplate and available capacity, and a breakdown of how the available capacity was provided to the market (*i.e.*, scheduled bilateral energy trades, committed reserve capacity, or capacity offered in spot trades via the Western System Power Pool bulletin board).

To monitor compliance with spot price mitigation, the Commission should require that all buyers and sellers of spot energy submit weekly reports to the Commission. Such reports should cover all spot wholesale transactions in which they engaged, including the relevant delivery hours, the prices and quantities traded, and the date and time of execution of the trade. Bilateral trades should be reported by the individual buyers and sellers independently, while trades through formal markets may be reported by the market operator (*e.g.*, transactions through the ISO's real-time Imbalance Energy market would be reported by the ISO).

The ISO recognizes that the reporting requirements recommended impose a non-trivial burden both on market participants to prepare these weekly reports and on the Commission to review them. The reports and their careful review by the Commission are, however, vital to ensuring compliance with the West-wide mitigation measures imposed by the Order. The Commission should resist the temptation to rely on a *caveat emptor* approach, whereby buyers who are charged an excessive price for spot energy would report to the Commission that a seller is violating the terms of the Order. First, such an approach cannot monitor compliance with the must-offer requirement since buyers will not know if all supply is being offered in accordance with the Commission's mandate. Second, at times when loads are high throughout an extensive geographic area and supplies are scarce, buyers faced with the threat of blackouts might be willing to pay excessive prices - *and not report them* – to obtain adequate supply. The ISO believes that if the Commission were to allow parties to "voluntarily" bypass the mitigation in this way it would only serve to undermine the intent of the mitigation plan, because under today's tight supply conditions it would leave open an opportunity for suppliers to withhold supply in hopes of obtaining excessive real-time bilateral prices.

In addition, reports should be made available on a confidential basis to entities with an interest in ensuring effective implementation of the West-wide mitigation approach such as the ISO. This is important for transparency and to maximize the usefulness of the reports.

Given the importance of the West-wide mitigation provisions in providing for just and reasonable rates, the Commission is correct in conditioning sellers' market-based rate authority on compliance by sellers with the requirements of those provisions. Since, the monitoring approach proposed here is required to enforce the West-wide mitigation provisions of the June 19 Order, the Commission should also make it clear that compliance with the reporting requirements recommended herein, are similarly a condition for sellers' market-based rate authority.

D. Compliance with the Must-Offer Requirement

In accordance with the June 19 Order, the ISO submitted its Compliance Filing on July 10, 2001. In its filing, the ISO explained,

> [t]o the extent that the June 19 Order does not provide detailed guidance on the implementation of certain of its provisions, however, the ISO has had to determine how best to implement certain aspects of the June 19 Order within the ISO's existing market structure.[25]

The ISO seeks clarification or rehearing of the following three issues only to the extent that the Commission finds that the July 10 Compliance Filing was inconsistent with its prior orders: (1) implementation of the must-offer requirement for Generating Units failing to submit adequate data or bids; (2) eligibility to set the Market Clearing Price; and (3) the reasonableness of the existing penalty provisions in Section 5.6.3 of the ISO Tariff.

1. Implementation of the Must-Offer Requirement for Generating Units Failing to Submit Adequate Data or Bids

The April 26 order imposed a "must-offer" requirement on all covered in-state generation, required certain generators to file heat and emissions rate data with the ISO, and provided for the calculation of proxy prices based on such data to establish price mitigation measures in Emergency hours. In its May 18, 2001, status report to the Commission, the ISO indicated that a number of units have failed to submit heat and emission rate data to the ISO. The ISO stated that in

[25] July 10 Compliance Filing at 5.

the case of generators that do not submit heat and emission rate data, the ISO will use reliable data to the extent it is available to calculate proxy prices (for example data from RMR contracts) or, if no such data is available, it would treat generators that fail to provide accurate heat and emission rate data as price takers. In its May 25 Order, the Commission accepted the ISO's proposal. May 25 Order, 95 FERC at 61,071.

In its June 19 Order, the Commission reiterated the must-offer requirement with regards to all covered units in California (and established a must-offer obligation for units throughout the rest of the West). In accordance with the May 25 and June 19 Orders, the ISO included in its July 10 Compliance Filing Tariff provisions to clarify treatment of units that fail to submit bids in accordance with the must-offer requirement and how the treatment is affected by whether or not a unit has filed accurate heat and emission rate data. The ISO explained its approach as follows:

> For all gas-fired generating units:
>
> - if a Scheduling Coordinator for any such unit has submitted adequate data but failed to bid all of its available capacity into the ISO real-time market, the ISO will insert a standing bid for such capacity at the calculated Proxy Price for such unit; but
>
> - if a Scheduling Coordinator for any unit has not submitted adequate data and has failed to bid, the ISO will insert a standing bid of $0/MWh.
>
> For all non-gas fired generating units:
>
> - if a Scheduling Coordinator fails to bid all of such unit's available capacity, the ISO will insert a standing bid of $0/MWh for all of such unit's un-bid available capacity.

The ISO believes this approach to be consistent with the Commission's price mitigation program. Such an approach provides strong incentives to suppliers to provide the data required by the Commission and to bid in accordance with the must-offer requirement. If the Commission's understanding of its prior orders is contrary to the ISO's implementation as reflected in the July 10 Compliance Filing, the ISO seeks rehearing and requests the Commission to modify the June 29 Order to allow for implementation of the must-offer requirement in accordance with the July 10 Compliance Filing.

2. Eligibility To Set the Market Clearing Price

In the July 10 Compliance Filing, the ISO noted that implementation of the price mitigation methodology raised two issues for the ISO with respect to determination of the Market Clearing Price:

> First, in stating that it will "not permit marketers to bid a price higher than the market clearing price", it is not clear whether the Commission is referring to the *maximum* Market Clearing Price during the hour *or* the Market Clearing Price during the hour. The ISO interprets the Commission's restriction to prevent marketers not only from bidding above the maximum Market Clearing Price for any given settlement period but also to prevent marketers from setting any Market Clearing Price in those periods where the market clears at a level below the maximum Market Clearing Price. For example, assume that the maximum Market Clearing Price in an hour in a non-System Emergency hour is \$100/MWh, that a non-marketer has a bid of \$70/MWh, a marketer has a bid of \$80/MWh, and that both bids are needed to meet demand. The ISO's interpretation of the Commission's order would establish a Market Clearing Price of \$70/MWh and would limit the marketer's payment to that price.
>
> Second, in the absence of having operational data and operational "visibility" (*i.e.*, telemetry) on the generating units of "other sellers" (*i.e.*, importers and other non-public utility generators in California), the ISO cannot distinguish such sellers from marketers. Moreover, absent such visibility, the ISO, and ultimately the Commission, will

> be unable to verify such resources' compliance with Commission's must-offer obligation and other requirements of the June 19 Order. The generating units of these "other sellers" should be visible to the ISO's monitoring systems as separate resources and should meet the ISO's scheduling and metering standards. Such standards are consistent with the standards required of Participating Generators. In order to resolve these implementation difficulties, the ISO proposes, in the first instance, to implement the Commission's order by only allowing "other sellers" (*i.e.*, importers and other non-public utility generators in California) who have signed a Participating Generating Agreement to set the Market Clearing Price and to seek to justify prices above the mitigated Market Clearing Price. Stated differently, in addition to marketers, the ISO proposes that all resources that have not signed a PGA be restricted from either setting the Market Clearing Price or being eligible to justify prices above the mitigated Market Clearing Price. Thus, only gas-fired units of Participating Generators are eligible to set the Market Clearing Price during System Emergency periods and only generating units under a PGA are eligible to set the Market Clearing Price during non-System Emergency hours.

July 10 Compliance Filing at 16-17 (footnotes omitted).

Again, only if the Commission determines that the ISO's implementation of the mitigation methodology is inconsistent with the June 19 Order does the ISO seek rehearing. The ISO believes its approach is necessary to enforce the Commission's obligation to ensure just and reasonable rates in California.

The ISO's interpretation of the limit on a marketer's ability to bid above *the* Market Clearing Price is consistent with the Commission's conclusion in the June 19 Order that a marketer should be no different than the last generator dispatched; it can recover the marginal costs of the last unit of energy produced. June 19 Order, slip op. at 40.

In addition, the ISO's interpretation that only out-of-state (and out-of-Control Area) sellers and other non-public utility generators in California that comply with ISO telemetry, metering and scheduling requirements and sign a

Participating Generator Agreement should be eligible to set the Market Clearing Price and justify prices above the Market Clearing Price is necessary to enforce the Commission's restrictions on marketers.

In particular, unless the ISO can "see" a resource in real-time, and verify the response of that resource against its schedules and ISO dispatch orders, the ISO cannot be certain that output claimed to be provided from a particular unit is in fact provided by the unit. Further, without schedules and meter data associated with a particular unit, the ISO cannot determine whether and to what extent output from a particular unit was in fact provided in response to an ISO dispatch instruction rather than to meet pre-existing commitments. Accordingly, the only practical manner by which the ISO can enforce the Commission's limitations on marketers, in the case of out-of-Control Area sellers and non-public utility generators in California, is by requiring them to comply with ISO requirements for Participating Generators.

3. The ISO Tariff's Existing Penalty Provisions for Non-Compliance With Emergency Dispatch Instructions Are Just and Reasonable.

In the June 19 Order, the Commission found that "during the periods mitigation is in effect, the current ISO provisions in . . . regard [to penalties for units forced out of service] are unjust and unreasonable," and, that therefore the ISO should modify its Tariff "so that the only penalty for having a unit forced out of service is the cost of replacement energy." June 19 Order, slip op. at 17. As the ISO explained in its July 10 Compliance Filing, the ISO believes this ruling is based on a misunderstanding of the ISO Tariff.[26] As there is no penalty in the ISO Tariff for Forced Outages, if the ISO is notified within the hour of the Outage, the ISO explained that no modifications were necessary to comply with the Commission's directives.[27]

In the Compliance Filing, the ISO also noted:

> With respect to scheduled Energy and the charges that would be incurred if a Scheduling Coordinator over-scheduled generation, the ISO Tariff is consistent with the Commission's directions that the "only penalty for having a unit forced out of service is the cost of replacement energy." Contrary to the arguments of Mirant, Reliant and Williams, the cost of replacement Energy under the ISO Tariff is *not* a penalty. The cost of replacement Energy consists of two charges: (1) Imbalance Energy charges, and (2) Deviation Replacement Reserve charges. Imbalance Energy charges reflect the cost of the Energy the ISO must procure to maintain Load and generation balance in real-time. Deviation Replacement Reserve charges reflect the cost of additional Replacement Reserve that the ISO purchases to ensure unscheduled deviations do not cause the ISO to violate applicable reliability criteria. As such, both charges are consistent with cost-causation principles and neither constitutes a penalty. In sum, if scheduled Energy is not delivered during normal operations or a System Emergency, there is a replacement Energy cost, but there is no penalty. If Instructed Energy is not delivered during a System Emergency (and no de-rate or outage is timely reported to the ISO) there is a penalty based on twice the replacement cost.

---

26 *See* the ISO's July 10 Compliance Filing at 10-12.

27 Section 5.6.3 of the ISO Tariff does provide for a penalty for failure to follow an ISO dispatch instruction. The penalty is equal to twice the highest price paid for Energy paid in the hour. However, Section 5.6.3.2 of the ISO Tariff also provides that a Participating Generator will not be subject to a penalty if it gives the ISO notice that the generating unit was physically incapable of responding to the instruction. Thus, there is *no* penalty for Forced Outages *if* the ISO is notified within the hour of the Outage. There *is* a penalty for failing to report Forced Outages. During a System Emergency a penalty based on twice the ISO's cost of replacement Energy may apply, but only in the event that the ISO is not notified within the operating hour of the de-rating in capacity or outage that causes the Participating Generator to be incapable of responding to ISO Dispatch Instructions. All generators are obligated to notify the ISO if they become unable to comply with a Dispatch Instruction during normal system operations (*see, e.g.,* Dispatch Protocol 9.2.2). Nothing in the June 19 Order suggests that it is unjust or unreasonable to impose a penalty on a generator that fails to comply with this obligation during a System Emergency.

July 10 Compliance Filing at 11-12.

Timely notification of a change in a generating unit's status is imperative if the ISO is to reliably operate the system and is consistent with the Commission's previous directives regarding the need for enhanced Outage coordination and, more generally, good utility practice.

Because the ISO Tariff is consistent with the Commission's determination that, in the context of the must-offer requirement, no penalties should apply for Forced Outages, no revisions are warranted in this regard. In the alternative, the ISO seeks rehearing of the June 19 Order to the extent that the Commission determined that Section 5.6.3 of the ISO Tariff required modification.

E. Other Issues

1. The Commission Should Clarify the Definition of Spot Markets in the WSCC.

In footnotes 3 and 9 of the June 19 Order, the Commission provides definitions of spot market transactions subject to mandatory price mitigation and forward markets not subject to mitigation. These definitions, however, are not completely consistent. Accordingly, the ISO believes that further clarification of the term "spot market" is needed. In addition, the ISO asks that the Commission expand its definition to include certain standard spot trading practices in the WSCC region which are not captured in the definition as stated in the Order.

Footnote 3 of the June 19 Order provides that "As used throughout this document, the terms 'spot markets' or 'spot market sales' means sales that are 24 hours or less and that are entered into the day of or day prior to delivery." This statement is clear that price mitigation applies to transactions that are entered into the day of or day prior to delivery and that are 24 hours or less in duration. It is also clear that it would apply to a block of hours less than 24 hours in duration, that commenced in the day that the transaction was executed even if that block of hours terminated the following operating day. An example of this would be a real-time off-peak transaction for a block of hours that started at Hour Ending ("HE") 2300 in the current day and terminated HE 0600 the following day. Finally, it is also clear that mitigation would apply to any next-day spot transaction of 24 hours or less. For example, it would apply to a transaction entered into early on a prior day, say HE 0700, for delivery the next day beginning in HE 1200.

Footnote 9 of the June 19 Order states "As used throughout this document, "forward contracts" or "forward transactions" means any transactions with a future delivery that are entered into more than 24 hours before commencement of service." This definition includes transactions that fall within "spot transactions" as defined in footnote 3 (*e.g.*, a contract entering into at HE700, for delivery the next day beginning in HE 1200). The ISO seeks clarification that footnote 9 should be interpreted to be consistent with the definition provided in footnote 3. That is, mitigation should apply to any day-ahead transaction, even if delivery commences more than 24 hours after the execution of the trade.

In addition, an expansion of the spot market definition in footnote 3 is needed because that definition does not take into account a standard spot trading practice in the WSCC region. To accommodate a normal work week, traders in the West typically negotiate daily spot transactions on Thursday for the following Friday and Saturday, and on Friday for the following Sunday and Monday. In these cases, spot trades for delivery on Saturday, Sunday and Monday are made more than one day in advance, and a delivery period of more than a single day may be included in a single transaction. This practice is also applied for holidays and to accommodate industry-wide meetings and seminars to the extent that they involve trading personnel.

Although the practice just described does not fit the explicit definition of spot market transactions in the June 19 Order, these transactions are genuine spot transactions which deviate from the definition only because of the occurrence of weekends, holidays and occasional special industry-wide events. The ISO therefore recommends that the Commission expand the definition of spot market transactions to include all trades that are negotiated on the last "trading day" prior to commencement of delivery, and that cover a delivery period that includes no more than 24 trading-day hours. For the purposes of this definition, “trading days” should be defined to mean Monday through Friday, excluding any holidays and other exceptions recognized by WSCC trading practices.

2. The Uplift Charges for Emissions and Start-up Fuel Costs Should Be Charges To All Users of the ISO Controlled Grid, Including Exports To Control Areas Outside California.

In the June 19 Order, the Commission responded to several rehearing requests contending that emissions costs should not be included as part of the Marginal Proxy Clearing Price, but should instead be collected as an uplift charge when actually incurred. Among the factors motivating this concern were that not all generators pay emission costs and those that do incur such costs pay them only when they have used up their emission allotments. The Commission also observed, however, that emissions costs were legitimate costs of producing energy, and that Generators were entitled to be paid for such costs.

Accordingly, the Commission excluded NOx emission mitigation costs from the calculation of the Marginal Proxy Clearing Price. Instead, it allowed generators to invoice the ISO for such costs when they are incurred pursuant to the must-offer obligation and an ISO dispatch order.

In order to allocate the costs of such emissions invoices, the Commission directed the ISO to develop a specific emissions allowance administrative charge. The Commission ordered that the administrative charge be assessed against all in-state load served by means of the ISO Controlled Grid, arguing that all customers within California benefit from cleaner air as a result of the application of these mitigation fees.

In the June 19 Order, the Commission also concluded that generators should have the opportunity to separately invoice the ISO for their start-up fuel costs when starting a unit in accordance with the must-offer requirement and an ISO dispatch order. It directed the ISO to develop tariff revisions to accomplish this consistent with the approach for emissions charges.

As directed by the Commission, the ISO's July 10 Compliance Filing included tariff revisions under which a charge for emissions costs is assessed against each Scheduling Coordinator based on its metered Demand within the

ISO Control Area and its Demand within California, but outside the ISO Control Area, that is served by exports from the ISO Control Area. The ISO allocated start-up charges in the same manner.

The ISO submits that the allocation of emissions costs mandated by the Commission is overly narrow, in that it fails to allocate costs to exports from the ISO Control Area to Control Areas outside of California. There is no reasonable distinction between exports from the ISO Control Area to Control Areas outside of California and export from the ISO Control Area to Control Areas within California. Thus, emissions costs should be allocated to Loads plus Exports outside of the ISO Control Area, including Exports to out-of-state Control Areas.

The emissions costs in question are one component of the costs of producing Imbalance Energy. In accordance with strict cost causation principles, the emissions costs should thus be allocated to entities purchasing Imbalance Energy in proportion to the amounts purchased. To the extent resources supporting out-of-state Exports deviate from their Day-Ahead and Hour-Ahead Schedules, Imbalance Energy purchases are made on behalf of the out-of-state Exports. Since Imbalance Energy purchases are made on behalf of out-of-state Exports, it is unfair to exempt such Exports from all emissions costs.

The Commission’s statement that Californian’s should pay emissions costs because they benefit from clean air is inapposite. When Californians purchase power from out-of-state resources, one component of the price of such power is the cost of any necessary environmental controls. This is true even though Californians may not directly benefit from the environmental quality that results from such controls. Similarly, when out-of-state loads purchase power from California resources, one component of the price of such power is the cost of any necessary environmental controls even though out-of-state loads may not benefit directly from the resulting environmental quality. In short, irrespective of who benefits, the cost of environmental controls is one of the costs of producing power that is legitimately included in power prices. While the ISO does not object to a less-than-perfect but practical approach to the allocation of emissions costs, the approach cannot unduly discriminate against California residents.

In the ISO's July 10 Compliance Filing, in light of the Commission's decision to allow Generators to invoice start-up fuel costs in the same manner as emissions costs, the ISO allocated start-up fuel costs in a consistent manner. To the extent the Commission revises the allocation of emissions costs, a similar revision would be appropriate with regard to start-up costs.

In sum, the allocation of emissions and start-up fuel costs only to California residents is unduly discriminatory. Emissions and start-up fuel costs can be allocated practically and fairly, if they are allocated to Loads in the ISO Control Area, plus Exports including Exports to Control Areas outside California.

V. CONCLUSION

Wherefore, for the reasons discussed above, the ISO respectfully requests that the Commission grant rehearing and clarification of the June 19 Order in accordance with the discussion above.

Respectfully submitted,

Charles F. Robinson General Counsel Roger E. Smith Senior Regulatory Counsel The California Independent System Operator Corporation 151 Blue Ravine Road Folsom, CA 95630 Tel: (916) 608-7135	Edward Berlin Kenneth G. Jaffe David B. Rubin Michael Ward Swidler Berlin Shereff Friedman, LLP 3000 K Street, N.W., Suite 300 Washington, DC 20007 Tel: (202) 424-7500

Dated: July 19, 2001

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in the above-captioned dockets.

Dated at Washington, DC, on this 19th day of July, 2001.

____

David B. Rubin
Sean A. Atkins
(202) 424-7500

ATTACHMENT A

Unit	Capacity, MW	Variable O&M rate, /MWh
ALAMIT_7_UNIT 1	140	$1.55
ALAMIT_7_UNIT 2	175	$1.55
ALAMIT_7_UNIT 3	320	$1.55
ALAMIT_7_UNIT 4	320	$1.55
ALAMIT_7_UNIT 5	480	$1.55
ALAMIT_7_UNIT 6	480	$1.55
COCOPP_7_UNIT 6	335	$0.99
COCOPP_7_UNIT 7	335	$0.99
ELSEGN_7_UNIT 3	335	$1.55
ELSEGN_7_UNIT 4	335	$1.55
ENCINA_7_EA1	99	$1.68
ENCINA_7_EA2	103	$2.59
ENCINA_7_EA3	109	$1.67
ENCINA_7_EA4	299	$1.05
ENCINA_7_EA5	329	$0.98
ETIWND_7_UNIT 1	115	$1.55
ETIWND_7_UNIT 2	132	$1.55
ETIWND_7_UNIT 3	320	$1.55
ETIWND_7_UNIT 4	320	$1.55
HNTGBH_7_UNIT 1	215	$1.55
HNTGBH_7_UNIT 2	215	$1.55
HUMBPP_7_UNIT 1*	52	$31.09
HUMBPP_7_UNIT 2*	52	$31.09
HUNTER_7_UNIT 2	100	$5.20
HUNTER_7_UNIT 3	100	$5.20
HUNTER_7_UNIT 4	163	$3.58
MNDALY_7_UNIT 1	215	$1.55
MNDALY_7_UNIT 2	215	$1.55
MOSSLD_7_UNIT 6	737	$1.30
OAK C_7_UNIT 1*	55	$400.00
OAK C_7_UNIT 2 *	55	$56.50
OAK C_7_UNIT 3 *	55	$67.34
PITTSP_7_UNIT 1	150	$0.76
PITTSP_7_UNIT 2	150	$0.76
PITTSP_7_UNIT 3	150	$0.76
PITTSP_7_UNIT 4	150	$0.76
PITTSP_7_UNIT 5	320	$0.76
PITTSP_7_UNIT 6	320	$0.76
PITTSP_7_UNIT 7	682	$2.42
POTRPP_7_UNIT 3	210	$3.92
REDOND_7_UNIT 5	175	$1.55
REDOND_7_UNIT 6	175	$1.55
SOBAY_7_SY1	145	$1.16
SOBAY_7_SY2	149	$1.14
SOBAY_7_SY3	174	$1.08
SOBAY_7_SY4	221	$0.73
Total	10481	

* indicates the units excluded from the MW-weighted average of $1.5527.