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 Nos. EL00-95-031 EL00-95-040 EL00-95-008
Investigation of Practices of the California Independent System Operator and the California Power Exchange	)	Docket Nos. EL00-98-038 EL00-98-033 EL00-98-009

MOTION FOR CLARIFICATION AND REQUEST FOR REHEARING OF THE ORDER ACCEPTING IN PART AND REJECTING IN PART COMPLIANCE FILINGS

The California Independent System Operator Corporation ("ISO")[1] respectfully submits this Motion for Clarification and Request for Rehearing of the Commission's "Order Accepting In Part And Rejecting In Part Compliance Filings" issued on December 19, 2001, in the above-identified dockets, 97 FERC ¶ 61, 293 (2001) ("December 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 December 19 Order, the Commission adopted some proposed Tariff revisions from the ISO's January 2, May 11, and July 10, 2001, compliance filings and its July 30, 2001 amendment to its May 11 and July 10 compliance filings ("January 2 Compliance Filing," "May 11 Compliance Filing," "July 10 Compliance Filing," and "July 30 Compliance Filing" respectively) responding to Commission orders issued on December 15, 2000,[2] April 26, 2001,[3] and June 19, 2001,[4] respectively. The compliance filings adopted in the December 19 Order implemented multiple aspects of the Commission's price mitigation plan for California and the larger western United States area of the Western Systems Coordinating Council ("WSCC").

The ISO appreciates that the Commission has accepted many of the ISO's proposed Tariff amendments implementing measures that 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 adopted Tariff revisions also help ensure the availability of adequate supplies of Energy, which will, in turn, permit the ISO to minimize System Emergencies and the potential of service curtailments and threats to the Control Area grid reliability.

There are, however, several aspects of the December 19 Order that perpetuate the potential for unjust and unreasonable rates in California markets

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

[2] 93 FERC ¶61,294 (2000), reh'g pending on some issues ("December 15 Order").

[3] 95 FERC ¶61,115 (2001), order on reh'g, 95 FERC ¶61,418 (2001), reh'g pending ("April 26 Order").

[4] 95 FERC ¶61,418 (2001), reh'g pending on some issues ("June 19 Order").

and therefore require modification. In addition, certain provisions of the December 19 Order create serious unintended negative consequences that reduce the viability of the ISO's real-time spot markets. Finally, the December 19 Order leaves a number of open questions relating to implementation of several aspects of the mitigation plan established by the Commission that must be resolved. The ISO therefore urges the Commission to modify and clarify its December 19 Order with respect to the following issues:

- the requirement that the ISO must declare a Stage 1 System Emergency when operating reserves drop below seven percent;
- the implementation of the must-offer obligation;
- the requirement that out-of-control area resources (interties) are eligible to set the Market Clearing Price ("MCP") without entering into a PGA; and
- the requirement that bids above the MCP but not accepted need not be justified to the ISO and Commission.

The ISO notes that, as it is preparing the instant filing, it, as well as Market Participants, has only had a few weeks' experience in implementing the December 19 Order. Thus, there is the possibility that the changes mandated by the December 19 Order may have unforeseen consequences or that other issues 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.

The ISO also notes that concurrent with the instant filing, the ISO is filing a Motion for Clarification and Request for Rehearing of the Commission's December 19, 2001, "Order on Clarification and Rehearing" in the above-cited dockets among others ("December 19 Rehearing Order"), 97 FERC ¶ 61, 275 (2001). The December 19 Rehearing Order, among other things, directs the ISO to make certain Tariff revisions concerning aspects of the price mitigation plan and includes discussion of some of the requirements that the Commission specifically imposes on the ISO in the December 19 Order. Accordingly, the ISO is seeking rehearing and clarification on several issues in both the instant filing and the ISO's rehearing request for the December 19 Rehearing Order.

II. BACKGROUND

The Commission 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.[5] In its April 26 Order, the Commission issued an order adopting a prospective market monitoring and mitigation plan for the 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;

[5] December 15 Order at 61,998-99.

- 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 by the ISO, 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. [6] 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."[7]

In its June 19 Order, the Commission 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 resource-specific "proxy prices" used to determine the MCP;

- 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 MCP 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;

[6] *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").

[7] *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.

- mandated that all marketers be "price takers" and not be able to set the MCP or be paid as-bid above the mitigated MCP; [8]

- 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;

- affirmed the ISO's proposed methodology for calculating proxy bids based on resource specific incremental cost curves derived from heat rate data;

- 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;

- directed the ISO to add 10 percent to the MCP 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;

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

The December 19 Order, by accepting in part and rejecting in part the ISO's compliance filings of May 2, May 11, and July 10, 2001, provides additional price mitigation provisions while clarifying the Commission's intent for implementation of certain directives previously issued. In particular, the December 19 Order:

- directed the ISO to modify the price mitigation sections of the Tariff to use the highest priced unit Dispatched during a reserve deficiency period using the

[8] 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.

Proxy Price to determine the mitigated reserve deficiency MCP, effective May 29, 2001, and the non-reserve deficiency MCP, effective June 21, 2001;

- rejected the ISO's proposal that sellers must submit cost justifications for bids that are above the mitigated MCP but which are not accepted;

- ordered the ISO to remove the Tariff provisions for Amendment No. 33 penalties for failure to respond to an ISO Dispatch instruction issued during an ISO-declared System Emergency;

- required the ISO to modify the Tariff such that the price established for Ancillary Services will be that as of the time the transaction was entered into and not at the time that delivery actually occurs;

- rejected the proposed requirement that to be eligible to set the MCP a generating unit must be under a PGA and instead ordered that units be eligible to set the MCP if the unit supplies heat rate and meter or interchange data to the ISO;

- clarified that emissions and start-up fuel costs are to be collected on an ISO Control Area Gross Load basis;

- clarified that the gas price used to determine start-up fuel costs is the same as that used to determine Proxy Prices in the real time markets;

- modified the ISO's proposed Tariff revisions to include addition of the ten percent credit risk adder to bids above the MCP that are accepted and cost justified;

- required the ISO to include in its Tariff the termination date of September 30, 2002 for the price mitigation plan; and

- accepted the previously filed revised Tariff sheet reflecting the Commission's rejection of Amendment No. 31 in Docket No. ER00-3673-00.

III. SPECIFICATIONS OF ERROR

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

A. Definition of Stage 1 System Emergency

The order errs by setting forth a fixed percentage of operating reserve, which, when not met, is the sole criterion by which the ISO must declare a Stage 1 System Emergency and thus recalculate the MCP and the Non-Emergency Clearing Price Limit.

B. Must-Offer Obligation

The order should be clarified that implementation of the must-offer obligation and reimbursement of minimum load operating costs (1) should include a "net of market revenue" methodology in which the ISO only is required to reimburse the generator for minimum load operating costs not recovered through other sales for the period of time the generating unit is required to operate in compliance with the must-offer obligation and (2) that the ISO can grant waivers to any generating units otherwise obligated to comply with the must-offer obligation but whose compliance the ISO determines is not required to ensure reliable operation of the ISO Control Area.

C. Out-Of-Control Area Resources Eligibility to Set the MCP

The order should be clarified that, to be eligible to set the MCP, any generating resource not under a Participating Generator Agreement ("PGA") must provide adequate telemetry and meter data that permit the ISO, on a specific resource basis, to verify that the resource can provide what it has bid and confirm that specific resource's operation and output in response to an ISO Dispatch instruction.

D. Cost Justification of Bids Above the MCP

The order errs in removing the requirement that bids above the MCP that are submitted but not accepted must be justified to the ISO and Commission.

IV. ARGUMENT

A. Recalculation of the Mitigated Market Clearing Price Should Be Triggered By Actual Operating Reserve Deficiencies Based Upon Western System Coordinating Council Minimum Operating Reliability Criteria

The December 19 Order requires the ISO "to modify its Tariff to make recalculation of the mitigated prices triggered when reserves in California fall below 7 percent." Slip or. At 9. In its April 26 Order, the Commission established price mitigation:

> "for all generators in California, including non-public utility generators, with available capacity during periods of reserve deficiency, defined as emergency situations beginning at Stage 1 (i.e.., when reserves are 7.5 percent or less)."[9]

By Motion for Clarification and Rehearing of the April 26 Order, the ISO explained that the ISO's Operating Reserve obligation was equal to the greater of the largest single system contingency, or the sum of five percent of the Load responsibility served by hydroelectric generation and seven percent of the Load responsibility served by thermal generation.[10] The ISO reaffirmed and expanded on this explanation in its Answer to Comments on its May 11 Compliance Filing.[11]

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[9] April 26 Order, slip o. at 14.
[10] ISO Motion for Clarification and Rehearing, filed May 25, 2001, at 5, FN 6.
[11] ISO Answer to Comments, etc., filed June 6, 2001, at 42.

In its June 19 Order, the Commission expanded price mitigation to all hours, and established a limit for MCP based on 85 percent 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." The Commission stated that "this maximum clearing price will remain in place until the next Stage 1 is declared and a new price is set."[12] The Commission also simplified the trigger for price mitigation by making clear that mitigation is triggered "when the ISO declares a reserve deficiency."[13]

In the December 19 Order, the Commission noted that commentors on both the ISO May 11 and July 10 Compliance Filings stated that the Commission had used the declaration of a Stage 1 System Emergency interchangeably with a seven percent reserve deficiency. However, the December 19 Order provides that "the Commission made clear that it is the reserve deficiency that creates a risk that prices might exceed those charged in a competitive market."[14] The Commission then requires "the ISO to modify its Tariff to make recalculation of the mitigated prices triggered when reserves in California fall below 7 percent. We find that establishing a specific percentage is appropriate and reasonable because it enhances market certainty during the mitigated period." *Id.* The Commission further states that "for the duration of the mitigation plan" the ISO's discretion to declare emergencies based on system conditions and other factors

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12 June 19 Order, slip op. at 7.

13 *Id.* at 43. Note that the Commission linked the price mitigation to a "reserve deficiency" and not to a Stage 1 System Emergency.

14 December 19 Order, slip op. at 8.

was “no longer warranted” since such discretion could “provide the appearance of manipulation of the market by the ISO.”[15]

The April 26, June 19 and December 19 Orders all reflect the Commission’s concern that periods of operating reserve deficiency should trigger recalculation of mitigated prices. The ISO believes, however, that the Commission, while properly recognizing that periods of inadequate Operating Reserve can result in potential for unjust and unreasonable prices, the Commission improperly links such a period with that which is properly a period for an ISO-declared System Emergency, as defined by the Western Systems Coordinating Council (“WSCC”) Minimum Operating Reliable Criteria (“MORC”) as further explained below.

A Stage 1 System Emergency occurs when the potential for an Operating Reserve[16] shortfall exists and available market and non-market resources potentially will be insufficient to maintain Operating Reserves in compliance with the WSCC MORC. If Operating Reserves are currently or are forecast to be below five percent of the ISO’s Load responsibility and reliability requirements, a Stage 2 System Emergency is declared. The ISO enters a Stage 3 System Emergency when Operating Reserves are currently or are forecast to be below 1.5 percent of the ISO’s Load responsibility and reliability requirements. The ISO is obligated to take affirmative action to maintain its full reserve obligation, and attempt to *avoid* the occurrence of any emergency, beginning with the avoidance of

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15 *Id.* at 9.

even Stage 1 System Emergencies. Many of the operational actions that the ISO undertakes to avoid an Operating Reserve deficiency are public and accordingly, sellers often know even before a Stage 1 System Emergency is announced that their resources will be required.[17]

The ISO's obligations in this regard arise in part out of its adherence to the FERC-approved WSCC reliability criteria. In its declaratory order concerning the WSCC's Reliability Management System ("RMS"), under which transmission operators agree, through contracts, to comply with WSCC reliability criteria, the Commission "acknowledg[ed] the longstanding role of WSCC in formulating regional reliability standards" and gave "substantial deference to WSCC in the development of reliability standards." *Western Systems Coordinating Council*, 87 FERC ¶ 61,060, 61,234 (1999). The ISO is committed to comply with the WSCC RMS by virtue of: (1) its contract with the WSCC,[18] (2) the provisions of the ISO Tariff,[19] and (3) California state law.[20]

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16 Defined in the ISO Tariff as "The combination of Spinning and Non-Spinning Reserve required to meet WSCC and NERC requirements for reliable operation of the ISO Control Area."

17 In accordance with ISO Operating Procedure E-508, the ISO may issue Alert and Warning notices, even before issuing emergency notices.

18 The ISO agreement is designated by the Commission as WSCC Rate Schedule No. 5.

19 Section 2.3.1.1.6 of the ISO Tariff states that the ISO should be the WSCC security coordinator for the ISO Controlled Grid. Under Section 2.3.1.3.1, the ISO is to exercise Operational Control over the ISO Controlled Grid "to meet planning and Operating Reserve Criteria no less stringent than those established by WSSC and NERC as those standards may be modified from time to time . . . ." *See also* Section 2.1 of the Dispatch Protocol of the ISO Tariff which provides:

> The ISO shall exercise Operational Control over the ISO Controlled Grid in compliance with all Applicable Reliability Criteria. Applicable Reliability Criteria are defined as the standards established by NERC, WSCC and Local Reliability Criteria and include the requirements of the Nuclear Regulatory Commission (NRC).

20 Chapter 345 of Assembly Bill 1890 provides:

> The Independent System Operator shall ensure efficient use and reliable operation of the transmission grid consistent with achievement of planning and operating reserve criteria no less stringent than those established by the Western

The WSCC RMS requires that the ISO (and all other Control Area operators in the WSCC) maintain Spinning Reserves and Non-Spinning Reserves equal to the greater of:

(1) The loss of generating capacity due to forced outages of generation or transmission equipment that would result from the most severe single contingency, or

(2) The sum of five percent of the load responsibility served by hydro generation and seven percent of the load responsibility served by thermal generation.[21]

In the case of the ISO it is the latter five percent and seven percent reserve criterion which is applicable.[22]

The ISO Operating Procedure E-508 specifies that the ISO will declare a Stage 1 System Emergency "any time it is clear that an Operating Reserve shortfall (when Operating Reserves are less than MORC minimum) is unavoidable." Implicit then, in any redefinition of a Stage 1 System Emergency, as the Commission appears to have so ordered, is a concurrent redefinition of the ISO's minimum Operating Reserve requirement. As the ISO has detailed to the Commission in its concurrently-filed ISO Request for Rehearing of the December 19 Rehearing Order, in prior filings in the above-cited dockets, and *supra*, the ISO's actual Operating Reserve obligation is not simply a fixed seven

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Systems Coordinating Council and the North American Electric Reliability Council.

21 WSCC Rate Schedule No. 1 First Revised Sheet No. 27.

22 Moreover, previously, the Commission has recognized that the ISO maintains Spinning Reserves and Non-Spinning Reserves equal to the greater of the sum of five percent of the load responsibility served by hydroelectric generation and seven percent of the load responsibility served by thermal generation. See, for example, *Duke Energy Oakland, et a.,* 84 FERC ¶ 61,960, n. 12 (1998) ("[f]or and demand met by hydroelectric resources, the 7% figure is reduced to 5%."; *El Segundo Power, LLC, et al.,* 84 FERC ¶ 61,011, 61,057 n. 9 (1998). Additionally, the WSCC RMS also has categories that includes other types of reserves beyond spinning and non-spinning that include, *e.g.,* regulation, designed to provide for more comprehensive reserve

percent, but instead is a varying function of its Load responsibility, including the variable amount of its Load served by hydroelectric generation and thermal resources, which may include other reliability requirements as set forth by WSCC MORC. Such other reliability requirements translate into variable reserve requirements for the ISO depending on system conditions.

Now the Commission apparently has ordered the ISO to alter the definition of a Stage 1 System Emergency to be coincident with a fixed actual value of reserve margin that does not comport with the WSCC MORC. Beyond the conflict with the WSCC MORC, the declaration of a Stage 1 System Emergency when Operating Reserves fall below seven percent is not guaranteed and is, in fact, unlikely to coincide with an actual Operating Reserve deficiency.

In 2001, the ISO's average Operating Reserve requirement was not seven percent, but 6.2 percent, based on the simple average of the monthly Operating Reserve obligations. Indeed, if the ISO were to operate using a seven percent threshold for the duration of the price mitigation period (until September 30, 2002), the ISO will incur a significant additional cost, which must be passed through to Market Participants, for the procurement of unnecessary and excessive Operating Reserves above the MORC requirements. The ISO does not believe that the Commission intended this consequence and the resulting burden on Market Participants and, ultimately, California's retail consumers of electricity.

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requirements as needed to ensure reliability in circumstances extending beyond the impact of a single contingency and its corresponding 5%/7% reserve requirement.

Given that it is not reasonable to think that the Commission intends that the ISO maintain excessive Operating Reserves, in its compliance filing in response to the December 19 Order, the ISO proposes a new Tariff term, "Price Mitigation Reserve Deficiency" which is defined as "Any clock hour in which the ISO's maximum actual reserve margin is below seven (7) percent." The Non-Emergency Clearing Price Limit will be reset whenever a Price Mitigation Reserve Deficiency occurs. This approach is consistent with the Commission's finding that a specific percentage is appropriate and reasonable because it enhances market certainty during the mitigated period and it avoids a temporary redefinition of a Stage 1 System Emergency that would conflict with the ISO's operation of the Control Area and ISO's compliance with the WSCC MORC requirements solely for a price mitigation plan soon to expire.

While the ISO agrees with the Commission's intent to ensure price mitigation takes effect at a consistent, transparent level of Operating Reserves, it is important that the trigger for a Price Mitigation Reserve Deficiency be set to a value that reflects the ISO's historical Operating Reserve obligation. The ISO now specifically requests the Commission modify its requirement of seven percent in favor of a 6.2 percent trigger for a Price Mitigation Reserve Deficiency as measured by the ISO's maximum actual (*i.e.,* real time) hourly Operating Reserve. As explained *supra*, 6.2 percent is a valid number reflecting last year's experience and a far more accurate indication of the existence of actual Operating Reserve deficiencies, which in turn contribute to unjust and unreasonable prices.

Accordingly, the ISO urges the Commission to revoke its order in this particular, adopt the ISO's proposal to create a Price Mitigation Reserve Deficiency and set the trigger of a Price Mitigation Reserve Deficiency when the maximum actual Operating Reserve for a full clock hour falls below 6.2 percent.

B. Implementation of the Must-Offer Obligation Entails Deeming All Generating Units Not Required For Reliability To Be On a Waiver Unless Otherwise Noticed By the ISO and Calculating Minimum Load Cost Reimbursement By Netting Market Revenue Against the Above Market Costs of Running At Minimum Load

The December 19 Order and December 19 Rehearing Order both address the must-offer obligation and clarify that generators subject to the obligation may recover their costs for complying with the ISO's instructions to keep their units on-line at minimum load status in order to be available for Dispatch instructions from the ISO. December 19 Order, slip op. at 7-9; December 19 Rehearing Order, slip op. at 87. The ISO will provide, in its responsive compliance filing to the December 19 Order, proposed Tariff revisions for the payment of minimum load costs, assessment of charges for the reimbursement of minimum load costs, to provide that the ISO will conduct an economic and reliability analysis the ISO conducts to identify which units are needed to be on-line at minimum load status, and the operation of the exemption (or waiver) policy through which the ISO grants waivers to generators not needed to be on-line at minimum load. The ISO's believes that its proposed implementation of the must-offer obligation produces a just and reasonable result balancing the generators' need for appropriate cost recovery with consumer protections against unreasonable rates. To the extent the Commission adopts the ISO's compliance filing in these particulars the ISO does not seek rehearing or clarification. Inasmuch as the ISO's implementation of the must-offer obligation is multi-faceted and individual aspects are necessarily interrelated, should the Commission determine that any parts of the compliance filing are inconsistent with the December 19 Orders requirements, the ISO seeks rehearing to the extent of the inconsistency.

C. The Commission's Order Removing the PGA Requirement to set the Market Clearing Price or to Justify Bids Above the Market Clearing Price Does Not Adequately Consider Prudent Information Requirements

As indicated in the ISO's July 10 Compliance Filing, the ISO's proposed requirement that generating units that wish to set the Market Clearing Price while price mitigation is in effect stems from the ISO's concerns that, absent the visibility and metering standards a generating unit must meet under a PGA, the ISO cannot conclusively distinguish units that are eligible to set the Market Clearing Price from other entities the Commission has clearly established cannot set the MCP.[23] The ISO did not intend to impose the PGA requirement as a means of gaining additional operational control over such resources, especially resources outside the ISO control area, whose operation may influence the prices paid in the ISO's markets but likely does not affect the reliability of the ISO Controlled Grid.

The ISO's concern about needing to tie a resource's ability to establish an ISO Market Clearing Price to the ISO's ability to see and verify that unit's actual performance should be plain, given the ISO's costly experience with megawatt laundering. To eliminate megawatt laundering, the Commission reasonably

[23] July 10, 2001 Transmittal Letter at 16.

required marketers to be price-takers. Granting resources outside the ISO Control Area the right to set the ISO Market Clearing Price without giving the ISO a means to verify that they can, and actually do, deliver their energy from the source they claim it to be from, invites a different form of megawatt laundering – one that, unlike the original form of megawatt laundering, may not begin in California, but one that nonetheless ends up setting a California, and potentially a west-wide, MCP. Given that now the Commission has rejected the ISO's proposal to require a PGA as one condition for eligibility to set a MCP, the ISO asks the Commission to affirm that real-time visibility is an essential condition to ensuring a proper MCP and that providing this visibility is a reasonable *quid pro quo* for the right to establish an ISO, and even a west-wide, MCP.

Various parties have argued that all the ISO need require for resources to establish the MCP is meter and interchange data. The ISO agrees that meter and interchange data would be sufficient to verify that the unit actually performed when dispatched by the ISO and to verify that the unit was operating at a point on its heat rate curve consistent with the price in its bid. What after-the-fact data cannot establish, however, is *whether the unit is capable of performing to its bid in the first place.* The ISO would not issue a Dispatch instruction, especially a Dispatch instruction that might result in a change in the MCP, to a resource the ISO knows cannot perform. In the ISO's experience, a bid is an offer, but not a commitment that is backed up by enforceable remedies, to perform. The ISO cannot know if a resource is capable of performing to its bid without real-time visibility of that resource. Without visibility, the resource could already be loaded to full capacity, or perhaps even off-line, though its bid may still stand.

The ISO and Market Participants must have confidence in the MCP. To prevent market uncertainty and administrative burden, the ISO must have real-time visibility of resources within the ISO Control Area to assess reliability and to validate those resources' bids so as to prevent resources that cannot respond to a Dispatch instruction from setting the price in the first place. To that end, the ISO should not be placed in a position of waiting until revenue quality metering data are available and, if necessary, retroactively issuing a revised MCP or rerunning settlement statements if it is subsequently determined that the out-of ISO Control Area unit did not perform.

As for resources outside of the ISO Control Area, while the ISO does not need real-time visibility of such resources to assess grid reliability,[24] the ISO needs real-time visibility for the reasons detailed *supra* to ensure a proper ISO MCP if those resources are to be eligible to set the MCP. To the extent that the Commission disagrees with these requirements, the ISO seeks rehearing.

D. The Commission's Elimination of the Requirement to Submit Cost Justification for Bids Above the Mitigated Market Clearing Prices But Not Accepted by the ISO Is Not Consistent With The Requirements Or The Intent of the Commission's Price Mitigation

The Commission's April 26 Order imposed price mitigation based on two premises: (1) that California resources were obligated to offer their capacity to the ISO and (2) that the marginal cost of the last gas-fired unit dispatched should set the MCP. This order also required suppliers to submit heat rate data to the

ISO and established a proxy figure for natural gas costs so that the ISO could calculate transparent unit-specific Proxy Prices that would be used to establish a mitigated MCP during times of Operating Reserve deficiency. The June 19 Order carried this price mitigation one step further by limiting the MCP during times when Operating Reserves were sufficient to eighty-five percent of the highest mitigated price established (by Proxy Prices, calculated from transparent heat rate and fuel price data) during the last Stage 1 System Emergency. Finally, the April 26 Order required that sellers must submit cost justification for transactions above the mitigated prices to the ISO and to the Commission. In sum, these measures established price mitigation based on two common themes: (1) a must-offer obligation, and (2) market clearing prices based on, in reserve deficiency periods and capped by, in non-reserve deficiency periods, a price determined by transparent information.

The Commission's decision to not require entities to submit cost justification for bids above the mitigated prices unless those bids are accepted by the ISO runs counter to these themes. Bidding at an unreasonable price effectively withholds capacity from the ISO and may drive up market clearing prices. If an unreasonably-priced bid must be selected, the generator submitting the bid must justify that bid, but if their justification is not accepted the only remedy applied is to require them to accept the MCP- a MCP that could have been driven up by their unreasonable bid from which all other resources, including resources in the generator's own portfolio, would unduly profit.

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[24] The operator of the Control Area in which those resources are located has that real-time responsibility.

Additionally, the unreasonable bid is not subject to the transparency embedded in a MCP established by pre-submitted heat rates and proxy gas costs during Operating Reserve deficiencies.

While the ISO does submit weekly market monitoring reports summarizing bidding behavior and identifying suppliers it believes are bidding at prices beyond what the ISO considers to be competitive levels to the Commission, these reports do not impose the proper burden on suppliers that justifying bids, even unaccepted bids, above the mitigated market clearing price would impose – a burden on suppliers to offer capacity at competitive prices or to affirmatively justify why they are not doing so.

IV. CONCLUSION

Wherefore, for the reasons discussed above, the ISO respectfully requests that the Commission revoke or otherwise revise the December 19 Order as requested above.

Respectfully submitted,

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Charles F. Robinson
Margaret A. Rostker
The California Independent System
Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630
TEL: (916) 608-7147

Dated: January 18, 2002

CALIFORNIA ISO

California Independent
System Operator

January 18, 2002

The Honorable Linwood A. Watson, Jr.
Acting Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange
Docket Nos. EL00-95-031, EL00-95-040, EL00-95-008

Investigation of Practices of the California Independent System Operator and the California Power Exchange
Docket Nos EL00-98-038, EL00-98-033, EL00-98-009

Dear Secretary Watson:

Enclosed for electronic filing please find The California Independent System Operator Corporation's Motion for Clarification and Request for Rehearing of the Order Accepting in Part and Rejecting in Part Compliance Filings in the above-referenced dockets.

Thank you for your assistance in this matter.

Respectfully submitted,

Margaret A. Rostker
Counsel for The California Independent
System Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630

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 Folsom, California, on this 18th day of January, 2002.

Margaret A. Rostker
Counsel for the California Independent
System Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630