UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company, Complainant, v. Sellers of Energy and Ancillary Service Into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange, Respondents.	)	Docket No. EL00-95-045
Investigation of Practices of the California Independent System Operator and the California Power Exchange	)	Docket No. EL00-98-042

INITIAL BRIEF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Charles F. Robinson
Vice President/General Counsel
Gene Waas, Regulatory Counsel
California Independent System
Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630
Phone: (916) 608-7144
Fax: (916) 608-7296

J. Phillip Jordan
Michael Kunselman
Swidler Berlin Shereff Friedman, LLP
3000 K Street, NW, Suite 300
Washington, DC 20007
Phone: (202) 424-7500
Fax: (202) 424-7643

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INTRODUCTION

Pursuant to the procedural schedule adopted in this proceeding, the California Independent System Operator Corporation ("ISO") submits its Initial Brief on the issue of how to determine the mitigated market clearing price ("MMCP") for the refund period. The MMCP will be referred to in this brief as the "mitigated price."

Following this introduction, the ISO's positions will be presented as proposed findings of fact under each of the headings and sub-headings in the Joint Narrative Stipulation of Issues ("Joint Narrative") adopted in this proceeding. The ISO has set up this brief so that the outline of the headings and sub-headings of the section on

Proposed Findings matches the outline of the Joint Narrative (*i.e.*, heading I.A in this brief matches heading I.A in the Joint Narrative).

The ISO's position is that the mitigated prices calculated by the ISO and contained in Exhibits ISO-17 and ISO-18 are the appropriate mitigated prices, subject to the modifications discussed in the next paragraph. These mitigated prices reflect the use of (i) incremental heat rates (*see* section I.B.1, below), (ii) points on the incremental heat rate curves corresponding to units' acknowledged operating targets based on ISO dispatches in the real time market (*see* section I.C below), and (iii) the mid-point of daily gas indexes (*see* section I.E.1, below). In addition, these mitigated prices are based on limiting the units eligible to set the mitigated price to gas-fired units that were dispatched in each interval through the ISO's Balancing Energy and Ex-Post Pricing ("BEEP") system. *See* sections I.D.1 and I.D.2.c, below.

Four modifications could be applied to these mitigated prices, including two that incorporate data and definitions agreed to through stipulation by the parties. First, calculated mitigated prices could use the heat rates of specific units developed through stipulation in this proceeding, as opposed to the heat rates initially submitted by the generators. *See* Exh. J-1 and section I.B.2, below. Second, gas-fired units eligible to set the mitigated price could be defined to include only units actually running on natural gas; this would exclude dual fuel units for intervals when these units were running on fuels other than natural gas. Third, the ISO's adjustment of the incremental heat rates to be monotonically non-decreasing could be eliminated; this would allow the incremental heat rate to decrease if that reflects the physical characteristic of a unit at a certain operating point. *See* section I.B.3, below. And fourth, in determining units eligible to be the marginal generating unit, any unit that did not in fact respond to an ISO dispatch instruction could be excluded. *See* section I.D.7, below. It is important to note that each of these four modifications, including those that would incorporate data and definitions agreed to through stipulation by the parties, could only result in lower mitigated prices than the prices in Exhibits ISO-17 and ISO-18.

As this brief will demonstrate, the mitigated prices in Exhibits ISO-17 and ISO-18 are consistent with the specific direction provided by the Commission and, when applied in mitigating historical transaction prices, reasonably approximate prices that would have been realized in a competitive market. On every issue where the parties now disagree, *e.g.*, whether to use average or incremental heat rates or what universe of units is eligible to set the mitigated prices, the ISO has followed the literal meaning of the Commission's orders. What is equally important, and what will become clear in the various sections of this brief, is that the ISO's approach is consistent with the underlying logic and objectives of those orders.

The Commission's fundamental approach to determining mitigated prices for both the future and the refund period was to approximate the prices that would result in a competitive market. The competitive market that the Commission sought to use in calculating this "proxy" for the wholesale market is the ISO's real time market for imbalance energy. The ISO's real time market is a ten-minute balancing market, and as such represents, chronologically, the "last minute" market for energy in the ISO system. Of necessity, this ten-minute market consists primarily of bids from units that are already operating. *See, e.g.,* Exh. ISO-19 at 25:8-13. As the Commission itself noted, an owner of a unit that is already operating should be willing to operate if the owner recovers the unit's marginal costs of production. *See* section I.B.1, below (argument under second proposed finding). Therefore, in order to approximate prices that would result in this market under competitive conditions, one must base "marginal costs" on the incremental heat rates associated with increasing (or decreasing) the output of each unit.

Moreover, during each ten-minute interval that the ISO operates its real time market, units with winning bids are dispatched by the ISO's market dispatching and pricing mechanism, the so-called "BEEP system." Therefore, in order to approximate the results of this market under competitive conditions, one must restrict the universe of units eligible to set a mitigated price to those that were *in that market*, *i.e.*, units that were dispatched through in the BEEP system based on bids in the BEEP stack. Approximating the results of this market under competitive conditions also requires that one determine the last unit dispatched using the same principles that are used in this market. Those principles are that the unit that is dispatched with the highest bid for incremental energy sets the price for incremental energy and, if no unit is dispatched for incremental energy, the unit that is dispatched with the lowest bid for decremental energy sets the price for incremental energy.

BACKGROUND – STATEMENT OF THE CASE

Consistent with the Presiding Judge's suggestion, the ISO will omit the customary background discussion. The ISO will be referring throughout this brief to five orders of the Commission and one report of the Chief Judge, with the following short-form citations:

? The "April 26 Order" is the *Order Establishing Prospective Mitigation and Monitoring Plan for the California Wholesale Electric Markets and Estab-*

lishing an Investigation of Public Utility Rates in Wholesale Western Energy Markets, 95 FERC ¶61,115 (2001).

? The "June 19 Order" is the *Order on Rehearing of the Monitoring and Mitigation Plan for the California Wholesale Electric Markets, Establishing West-Wide Mitigation, and Establishing Settlement Conference,* 95 FERC ¶61,418 (2001).

? The "Chief Judge's Report" is the *Report and Recommendation of Chief Judge and Certification of Record,* 96 FERC ¶63,007 (Wagner, C.J.) (2001).

? The "July 25 Order" is the *Order Establishing Evidentiary Hearing Procedures, Granting Rehearing in Part, and Denying Rehearing in Part*, 96 FERC ¶61,120 (2001).

? The "December 19 Order on Clarification and Rehearing" is the *Order on Clarification and Rehearing*, 97 FERC ¶61,275 (2001).

? The "December 19 Order on Compliance Filings" is the *Order Accepting in Part and Rejecting in Part Compliance Filings* in Docket Nos. EL00-95-034, et al., 97 FERC ¶61,293 (2001).

I. HOW ARE THE MITIGATED MARKET CLEARING PRICES DETERMINED FOR EACH 10-MINUTE INTERVAL DURING THE REFUND PERIOD?

A. What is the applicable formula for determining the MMCPs for each interval?

Proposed Finding: **The formula is**

***MMCP* = ([Heat Rate x Gas Price] + $6.00) x 1.1 (beginning January 6*)*.**

Argument:

The ISO believes all parties have agreed that this is the formula required by the Commission.

B. What is the appropriate heat rate data set for each unit eligible to set the MMCP that should be referenced for insertion in the MMCP Formula?

1. Should average and/or incremental heat rate curves be used in the determination of the MMCP?

<u>First Proposed Finding</u>: The Commission requires that incremental heat rate curves be used in the calculation of the mitigated prices for the refund period.

<u>Argument:</u>

The most reasonable interpretation of the Commission's specific direction and the Commission's overall objective of replicating a competitive market price support the ISO's use of incremental heat rates, *i.e.*, heat rates that do not include minimum load fuel costs, [1] in calculating mitigated prices for determining refunds. The Commission has required the ISO to use the same elements in calculating the mitigated prices for the refund period as the Commission endorsed for use by the ISO in calculating proxy prices in periods of reserve deficiency on a going-forward basis (*i.e*., beyond the refund period), except in those specific instances in which the Commission has determined that an element used in the calculation for the refund period should be different. The Commission's April 26 and June 19 Orders expressly ordered the ISO to use incremental heat rates in calculating the marginal costs of individual generating units and the mitigated market clearing prices for real time energy in periods of reserve deficiency on a going-forward basis, and has approved the ISO's compliance filing using incremental heat rates to calculate such proxy prices. The Commission has never suggested that the ISO should use different heat rates in calculating mitigated prices for the refund period.

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[1] Incremental heat rates do not include minimum load (or "no load") fuel costs, while average heat rates do include such costs. *See* Exh. ISO-5 at 14, n. 4.

There are five relevant Commission orders: two orders dealing with calculation of proxy prices in periods of reserve deficiency (April 26 and June 19), one order dealing with the ISO's compliance filings pursuant to those two orders on proxy prices (December 19 Order on Compliance Filings), and two orders dealing with calculation of mitigated prices for the refund period (July 25 Order and December 19 Order on Clarification and Rehearing). The two orders dealing with calculation of proxy prices, as well as the order dealing with the ISO's compliance filings, establish that the Commission intended the ISO to use incremental heat rates for that purpose. The two orders dealing with the calculation of mitigated prices for the refund period establish that the Commission intended the ISO to use the same heat rates in calculating mitigated prices.

The Commission first addressed the heat rate to be used in calculating the marginal costs of individual generating units and the mitigated market clearing price in the ISO's real time market in its April 26 Order. There, it required each owner or operator of gas-fired generation in California to provide to the ISO the heat rate for each generating unit. The Commission expressly required that these heat rates be incremental heat rates: "These heat rates must reflect operational heat rates that do not include start-up and minimum load fuel costs . . . ." 95 FERC at 61,359. The Commission also expressly directed the ISO to use these incremental heat rates in calculating the proxy price: "The ISO will use these heat rates to calculate a marginal cost for each generator . . . ." *Id.* In these passages the Commission also made clear that the "marginal cost" of a generating unit is calculated by using incremental heat rates.

In the June 19 Order, on rehearing of the April 26 Order, the Commission reaffirmed that the ISO should use incremental heat rates in calculating proxy prices. That reaffirmation was evidenced in at least three ways. First, in the "Introduction and Summary" of that Order, the Commission twice stated that it was retaining the requirement that proxy prices be based on marginal costs, which, as noted above, the Commission in the April 26 Order had stated were to be calculated using incremental heat rates.[2] Second, in that same section of the June 19 Order, the Commission listed its "three adjustments to the clearing price methodology" from the April 26 Order, and none of those adjustments involved the heat rates to be used. 95 FERC at 62,548.[3] Finally, in the section of the Order specifically addressing heat rates, the Commission noted that the April 26 Order had required the use of heat rates that did not include minimum load fuel costs, recounted that the ISO was collecting heat rates at eleven operating points in order to comply, and expressly stated that "by collecting eleven different operating points, the ISO will be able to approximate the actual *incremental* cost curve of each generating unit and thereby develop representative proxy prices for each unit throughout the unit's operating range." 95 FERC at 62,563 (emphasis added).

The Commission first addressed the method of calculating mitigated prices for the refund period in its July 25 Order. Prior to that Order, the Commission had

[2] The first statement: "We will continue to use a single market clearing price derived from must offer and marginal cost bidding requirements for hours of reserve deficiency in California's organized spot market." 95 FERC at 62,547. The second statement: "We will retain the use of a single market clearing price with must offer and marginal cost bidding requirements for sales in the ISO's spot markets in reserve deficiency hours . . . ." *Id.* at 62,548. In addition, later in the June 19 Order the Commission again characterized its mitigation plan as being based on marginal costs: "The Commission's mitigation plan is based on the payment of the marginal cost of the last generator dispatched to serve the last increment of load." *Id.* at 62,560.

received the recommendations of the Chief Judge, dated July 12, concerning the methodology the Commission should order the ISO to use in calculating those mitigated prices. The Chief Judge had noted that "[t]he June 19 Order established a mitigated price based upon the marginal cost of the last unit dispatched to meet load in the CAISO's real time market," and had "recommend[ed] that the methodology set forth in the June 19 Order be used with the modifications discussed below in order to calculate any potential refunds [during the refund period]." 96 FERC at 65,040. None of the Chief Judge's suggested modifications to the methodology in the June 19 Order involved the heat rates to be used.[4] In the July 25 Order, the Commission stated that "[w]e will adopt the recommendations of the Chief Judge, as modified below, and apply the methodology set out in the June 19 Order [to determine refunds for the refund period]." 96 FERC at 61,516. The Commission's only modification to the Chief Judge's proposal did not affect the heat rates to be used.[5] Moreover, in describing the essence of the methodology of the June 19 Order, which it was adopting also for the refund period, the Commission stated that "[t]he June 19 Order established a mitigated price based upon the marginal cost of the last unit dispatched to meet load in the ISO's real time market." *Id.* at 61,517. As noted above, the Commission had established in the April 26 Order that marginal costs were calculated by using incremental heat rates. Thus, it is clear that the Commission intended in the July 25 Order that incremental heat rates be used in calculating

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[3] The three adjustments were (1) to require marketers to be price takers; (2) to revise the gas prices to be used in calculating the proxy price; and (3) to establish a mechanism for generators to recover their start-up and emissions costs. *See* 95 FERC at 62,548.

[4] The suggested modifications involved the gas prices to be used, and the omission for the refund period of the requirement that prices in periods of non-reserve deficiency not exceed 85% of the mitigated price calculated for the last period of reserve deficiency. *See* 96 FERC at 65,040.

[5] The modification was to increase the number of sources for the gas price to be used in the mitigated price calculation. *See* 96 FERC at 61,518.

mitigated prices for the refund period, as they were in calculating proxy prices during periods of reserve deficiency.

The Commission dealt with requests for rehearing of the July 25 Order in the December 19 Order on Clarification and Rehearing. Several aspects of the latter order reaffirmed that the Commission intended that the ISO use incremental heat rates in calculating mitigated prices for the refund period. First, in the "Introduction and Summary" section, the Commission reconfirmed both (i) that the "formula for determining the amount of any refunds . . . is based substantially on the approach adopted for mitigation prospectively," 97 FERC at 62,171, and (ii) that "[t]he mitigated reserve deficiency MCP is the *marginal cost* of the last unit dispatched to serve the last increment of load during a period of reserve deficiency." *Id.* at 62,172 and n.6 (emphasis added). Second, when it subsequently described the July 25 Order governing refunds and the April 26 and June 19 Orders governing prospective mitigation, the Commission once again confirmed (i) that "[t]he refund methodology adopted most of the criteria of the June 19 price mitigation plan," *id.* at 62,178, (ii) that "[h]ourly mitigated prices [for the refund period] would be developed using the *marginal costs* of the last unit dispatched to meet load in the ISO's real time market," *id.* (emphasis added), and (iii) that "[t]he mitigated reserve deficiency MCP [for prospective mitigation] is the *marginal cost* of the last unit dispatched . . . ." *Id.* at 62,177 and n.20 (emphasis added). And finally, in discussing specific requests for rehearing addressed to elements of the mitigated pricing formulas for the prospective and refund periods, the Commission reaffirmed (i) that "[t]he mitigated reserve deficiency MCP [for the prospective period] is . . . based on a single price which is set by the *marginal cost* of the last unit produced . . . ," *id.* at 62,212 (emphasis added), and (ii) that "we will not allow any additional cost items to be included in the refund formula because "[t]o hold otherwise would be inconsistent with our *marginal cost based approach*." *Id.* at 62,214 (emphasis added).

From these reviews of the April 26, June 19 and July 25 Orders and the December 19 Order on Clarification and Rehearing, it is clear that the Commission has never departed from either (i) the explicit statement in the April 26 Order that the heat rates to be used by the ISO should be incremental heat rates, *i.e.*, heat rates that do not include minimum load fuel costs, or (ii) the identity, also first established in the April 26 Order, between using incremental heat rates and determining the marginal costs of the last unit dispatched. Absolutely the *only* statement in *any* Commission order that any party has identified as casting doubt on this conclusion is a statement in the June 19 Order, in the context of addressing a rehearing request by Williams, that "[t]he ISO's heat rate curve reflects the minimum load fuel requirements requested by Williams." 95 FERC at 62,563. Mr. Tranen, a witness for the California Generators, points to that statement as establishing that the Commission "reversed" its determination in the April 26 Order that incremental heat rates should be used. Exh. GEN-1 at 17:17 – 18:5. There are two independent sources of evidence that Mr. Tranen has misread the Commission's statement.

First, as noted above in the discussion of the various orders, the Commission in the April 26 Order clearly equated using incremental heat rates with establishing the "marginal costs" of the last unit dispatched, and throughout the remaining orders the Commission continued to refer to the methodologies for determining both proxy prices for the future period and mitigated prices for the refund period as including determination of the "marginal costs" of the last unit dispatched. Thus, there was no change in the Commission's description of the methodologies after its reference in the June 19 Order to the ISO's heat rate curves as "reflecting" minimum load fuel costs. This shows that, whatever the Commission meant by that reference, it did not mean to change the fundamental point it had established in the April 26 Order – that the ISO was to calculate proxy prices (and, after the July 25 Order, mitigated prices for the refund period) using incremental heat rates.

Second, following the reference in the June 19 Order to the ISO's heat rate curves as "reflecting" minimum load fuel costs, the Commission has accepted the portions of the ISO's compliance filing pursuant to the April 26 Order in which the ISO made clear that it was using incremental heat rates to calculate proxy prices for periods of reserve deficiency. *See* December 19 Order on Compliance Filings. In that Compliance Order, the Commission *again* reiterated that "[t]he mitigated reserve deficiency MCP is the *marginal cost* of the last unit dispatched to serve the last increment of load during a period of reserve deficiency." *Id.* at 62,361 and n.7 (emphasis added). In other words, the Commission accepted a compliance filing in which the ISO explicitly stated, both in the filing letter and in proposed Tariff language, that it was using incremental heat rates, and in doing so the Commission again stated that the marginal cost of the last unit dispatched – which in the April 26 Order it had equated with use of incremental heat rates – would be used in the calculation of proxy prices. *See* Items by Reference B (excerpts from ISO compliance filing) and C (excerpts from ISO status report).

Against this background it cannot be assumed that the Commission *sub silento* reversed its requirement from the April 26 Order that the ISO use incremental heat rates, when it made the statement in the June 19 Order concerning the ISO's heat rates "reflecting" minimum load fuel costs. There are two possible explanations for the statement. First, the Commission could have simply erred. Or, more likely, the Commission intended its statement to be read in the context that Williams was seeking recovery of both start-up costs and minimum load fuel costs. The Commission expressly granted Williams's request that generators recover start-up fuel costs, and concluded the discussion by noting that "*[t]his change* [*i.e.*, allowed recovery of start-up fuel costs] adequately reflects the concerns raised by Williams." 95 FERC at 62,563 (emphasis added). It appears that the Commission was giving Williams "half a loaf," *i.e.*, it was granting rehearing to require the ISO to pay start-up fuel costs but denying rehearing to the extent Williams was seeking to require the ISO to use something other than incremental heat rates. Read this way, the Commission's reference to the ISO's heat rate curves "reflecting minimum load fuel requirements" was simply a passing reference to the heat rate curves being obtained by the ISO from generators, which the ISO would then convert to incremental heat rate curves. As Staff witness Mr. Sammon has pointed out, if the Commission had intended to reverse its previous requirement that the ISO use incremental heat rates, it would presumably have done so more directly and explained why it was doing so. *See* Exh. S-26 at 22:5-14.

<u>Second Proposed Finding</u>: Use of incremental heat rate curves is required in order to replicate the results of a competitive real time market, as intended by the Commission.

<u>Argument:</u>

The Commission has stated on several occasions that the basic intent of the methodologies for determining proxy prices in times of reserve deficiency on a going forward basis and the mitigated prices during the refund period is to produce prices that approximate the results in a "competitive market." For example, in the December 19 Order on Clarification and Rehearing, referring to both methodologies, *i.e.*, the prospective one and the one for the refund period, the Commission generalized as follows:

> [W]e have mitigated prices [in order] to ensure they are no higher than those that would result in a competitive market, *i.e.*, at a price no higher than the cost of the least efficient generating unit needed to meet load, for the period October 2, 2000 through September 30, 2002, when we predict conditions to be adequate to revert to pricing based on market prices without regulatory price intervention.

97 FERC at 62,172. Later in the same Order, referring specifically to the methodology for the refund period, the Commission stated: "Under the methodology, refunds would be determined by the difference between prices charged and a competitive market base-line calculated for each hour of the refund period." *Id.* at 62,178. These statements echo many previous and contemporaneous Commission (and Chief Judge) statements to the same effect, that the intent of both the prospective and retrospective methodologies was to replicate prices in a competitive market. *See, e.g.,Id.* at 62,212 (December 19 Order on Clarification and Rehearing) (plan in the June 19 Order was "intended to replicate the price that would be paid in a competitive market"); 97 FERC at 62,368 (December 19 Order on Compliance Filings) ("The Commission has consistently held that for purposes of mitigating the California market, the ISO must institute a mechanism that emulates a competitive market . . . ."); 96 FERC at 65,039 – 65,040 (Chief Judge's Report) (apply the basic methodology of the June 19 Order to the refund period in order "[t]o re-create … the competitive market….").

Given that the Commission's intention, indisputably, was to approximate the outcome of a "competitive market," the relevant question becomes: Which heat rate curve is consistent with a competitive *real time* market, the incremental heat rate curve or the average heat rate curve? The Commission answered this question in the April 26 Order. There, as noted earlier, the Commission concluded that *incremental* heat rates, *i.e*., heat rates that do not include minimum load fuel costs, should be used to determine the *marginal costs* of the last unit dispatched. 95 FERC at 61,359. Then, the Commission flatly stated that "[t]he use of *marginal cost pricing* generally reflects the prices that would be bid into an auction by generators in a *competitive market*." *Id.* at 61,363 (emphasis added). The Commission elaborated on this conclusion in the course of explaining why it was settling on marginal cost pricing and rejecting various other proposals, including one that bidders should be allowed to recover their *variable costs*:

> The Commission finds that using marginal costs is the appropriate method for calculating bids during price mitigation. During a period when a supplier has available capacity, it should be willing to sell that capacity on a daily basis as long as it covers its marginal cost of producing it. Since marginal cost pricing best approximates competitive pricing, there is no need to include fixed *or other costs* in the bids.

Id. at 61,362 (emphasis added). The Commission did not stop there; it also explained *why* the use of marginal cost pricing (for which it had required the use of incremental heat rates) reflects the way generators would bid into a competitive real time market:

> [T]he amount received through the real-time auction applies only to capacity available in the real-time market after their bilateral contracts are honored. Since bilateral contracts should be the principal means by which generators recover their total costs, generators should be willing to sell any residual real-time energy for any price at or higher than their marginal cost.

Id. at 61,364.

The record is clear. The Commission (i) has stated that the very purpose of the price mitigation methodologies, for both the prospective and the refund periods, is to approximate the outcome of a competitive real time market, and (ii) has concluded that in a competitive real time market, bidders should be willing to sell if they can recover their marginal costs, which are determined by using incremental heat rates.

The Commission's conclusion with respect to a competitive real time market is perfectly consistent with both economic principles and the reality of wholesale energy markets. As the Commission noted in the passage last quoted, above, generators should be depending primarily on bilateral contracts. When entering into such contracts, generators should be expected at least to recover their costs, including their minimum load fuel costs. They should be willing to sell into the real time auction market the energy from any capacity not already committed, so long as they recover the marginal costs of producing that energy – and the marginal costs are determined from the incremental heat rate curve. If they were allowed to recover for energy sold into the real time market based on their average heat rate curves, they would actually recover their minimum load fuel costs *twice* – once under the bilateral contract, and again in the real time market.[6]

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[6] The economic point made in the text is consistent with the Commission's conclusion that generators with long start-up times should be paid their minimum load fuel costs under the prospective mitigation methodology if the ISO requires them to be on line at minimum load when they are not otherwise running pursuant to a bilateral contract, but then does not dispatch them during real time. *See* 97 FERC at 62,363. The requirement to pay minimum load fuel costs in this circumstance arises because of the must-offer requirement that is part of the prospective mitigation plan; because the units' long start-up times require that they be at minimum load in real time in order to offer their output, it is only fair that they be compensated for

Moreover, use of average heat rate curves would also lead to mitigated prices that are simply incompatible with the Commission's overall intent to approximate the outcome of a competitive market in terms of both the "marginal unit" used to set the mitigated price and the overall price trends that result. First, if average heat rates are used, the mitigated price will frequently be set by units operating at or near their minimum operating levels. This is intuitively obvious, as average heat rates of most units are very high at minimum operating levels and then decrease rapidly. *See* Exh. ISO-8. Yet, this mitigated price would be applied to *all* units that were operating. It is counter to common sense to derive a price based on units operating at minimum load precisely because their output was *not needed*, and then apply that price to units almost all of whose capacity was called upon at or near *maximum output* ; the Commission has recognized as much.[7] In addition, deriving a price based on average heat rate curves would also lead to higher mitigated prices during *off-peak hours* relative to peak hours – directly the opposite of price trends that result in competitive energy markets.[8] *See* Exh. ISO-19 at 10:11 – 14:21.

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those minimum load fuel costs if they are not otherwise running to meet bilateral contractual obligations. During the refund period, however, there was no must-offer obligation and the Commission has rejected the concept of mimicking that obligation by assuming availability of all units that were not on outage during an interval; instead, the Commission has limited eligibility to set the mitigated price to those units that actually were dispatched in each interval. *See* 96 FERC at 61,517 (July 25 Order). Thus, for the refund period, any unit that was dispatched in the real time market had bid into that market. As the Commission stated in the passages discussed in the text, any unit that bid into the real time market should seek to recover only its *marginal costs* of producing the energy associated with capacity still available in real time, as it already has recovered other costs (including minimum load fuel costs) through bilateral contracts or forward energy markets.

[7] Note that the Commission in the April 26 Order, in explaining why it was requiring the proxy price to be based upon marginal costs and incremental heat rate curves, stated that units should be operating at or near maximum output when supplies were stretched. 95 FERC at 61,359. In the June 19 Order, the Commission repeated that requiring use of incremental heat rates was "justified because the market clearing price should reflect the costs needed to operate *at or near maximum output*." 95 FERC at 62,563 (emphasis added).

[8] The Commission emphasized the way prices are expected to behave in a competitive market in the December 19 Order on Clarification and Rehearing. There, in explaining why it had, in the June 19 Order, capped the market clearing price for periods of non-reserve deficiency at 85% of the proxy price calculated

2. Which heat rate source data should be used and are the data accurate?

<u>Proposed Finding:</u> Incremental heat rates should be calculated from the heat rate data supplied to the ISO by generators pursuant to the April 26 Order, as modified by the Stipulation as to Heat Rates and Non-Gas Generation, Exh. J-1.

<u>Argument:</u> The parties have stipulated to the use of this data, whether incremental or average heat rates are to be used to calculate the mitigated prices. *See* Exh. J-1.

3. If incremental heat rate curves are used, should they be adjusted to be monotonically non-decreasing?

<u>Proposed Finding:</u> It is not necessary to adjust the incremental heat rates to make them monotonically non-decreasing.

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in the last reserve-deficiency hour, the Commission stated: "Under competitive conditions, the market is expected to clear at a lower price during non-reserve deficiency hours, as opposed to reserve deficiency hours, because there would be excess generation available to serve the load. . . . Thus, the arrangement seeks to simulate the results of a competitive market, where prices will be lower when supply is higher relative to demand." 97 FERC at 62,247. In hours of peak demand during a day (just as in hours of reserve deficiency), supply is lower relative to demand and prices will be higher; in non-peak hours (just as in hours of non-reserve deficiency), supply is higher relative to demand, and prices will be lower.

Argument:

The incremental heat rate for a given generating unit may not always increase as output from the unit increases. *See* Exh. ISO-5 at 11:7 – 12 (Figure 3). Before determining the marginal unit for each interval for purposes of calculating the mitigated price, the ISO adjusted the incremental heat rate curves of specific units as necessary to ensure that they were either constant or increasing at each increased level of output, *i.e.*, that they were "monotonically non-decreasing." *Id.* at 26:16 – 27:3. The primary reason the ISO did so was to align the determination of the marginal units during the refund period with the ISO's dispatch algorithm and the way in which marginal units are determined for the prospective period (when the ISO sets proxy prices during periods of resource deficiency pursuant to the April 26 and June 19 Orders.) *Id.* at 27:5 – 32:6.

In responsive testimony, witnesses for both the California Generators and the California Parties noted that it is not necessary to establish monotonically non-decreasing heat rates for the refund period, since for that historical period the ISO does not need to use its dispatch algorithms, as it might need to do for forward-looking price mitigation. Exh. GEN-1 at 12:20 – 15:2; CAL-1 at 16:10 – 20:15. The ISO thereafter acknowledged that the adjustment of incremental heat rates to be monotonically non-decreasing could be eliminated for the refund period. Exh. ISO-20 at 8:11 – 9:7.

C. At what operating point on the heat rate curve should a unit's heat rate be taken for insertion into the MMCP Formula?

Proposed Finding: **The incremental heat rate of each unit eligible to be selected as the marginal unit should be determined at the point on the heat rate curve that corresponds to the unit's Acknowledged Operating Target ("AOT"), which is the operating point at which the unit was dispatched by the ISO in the real time market.**

Argument:

The AOT is defined as "the Final Hour-Ahead Schedule for Energy submitted for each unit, plus any real-time Energy dispatched by the ISO [in the real time market] during that hour." Exh. ISO-1 at 29:6-9. The Final Hour-Ahead Schedule for Energy shows the scheduled operating level of a unit each hour (prior to real time) based on bilateral arrangements or accepted bids into the PX or other exchanges. *See* Exh. ISO-1 at 29:1 – 33:4 (presenting examples).

The ISO developed the concept of the AOT immediately after the Commission issued the June 19 Order, in order to calculate mitigated prices and an estimate of refunds as directed by the Chief Administrative Law Judge in preparation for the settlement conference ordered by the Commission. Tr. 1594:7-19. The concept of AOT was developed in order to effectuate the Commission's directive in the June 19 Order that the ISO "calculate the proxy market clearing price based upon *the approximate point on the heat rate curve at which the last unit is dispatched*." 95 FERC at 62,563 (emphasis added). *See* Tr. 1594:7 – 1596:11. Applying the concept of AOT to the refund period replicates how the ISO determines the heat rates used in calculating cost-based bids or "proxy" bids and mitigated prices under the April 26 and June 19 Orders. The use of the AOT to approximate the point on a unit's heat rates curve at which it was dispatched in the real time market has been clearly and consistently documented in calculations the ISO has submitted in these proceedings, *see* Tr. 1595:22- 1596:11; while the Chief Judge and the Commission specified a limited number of other changes in the ISO's methodology, neither suggested any change to this concept.

The fact that the AOT represents the level at which a unit is dispatched in the real time market has not been disputed. For example, it is indisputable that a unit with a Final Hour-Ahead Schedule of 125 MWs, which then acknowledges a real time ISO dispatch of 50 MWs, has been *dispatched* at an output level of 175 MWs, *regardless* of the output level at which the unit actually operates. Taking the incremental heat rate at 175 MWs thus implements the Commission's directive to calculate the mitigated price based on the approximate point on the heat rate curve at which the last unit is dispatched in the real time market.

Arguments that the mitigated pricing methodology should take the heat rate at the point on the curve at which the marginal unit actually operated are fatally flawed in two respects. First, those arguments do not square with the Commission's directive to use the point on the curve at which the unit was "dispatched." Second, they ignore the fact that any deviation by the unit from the level at which it was dispatched is just that – a deviation and, moreover, an uninstructed deviation. Most parties in this proceeding agree that a unit should not be eligible to be the marginal unit based on its provision of uninstructed energy, *i.e.*, its over- or under-generation based on its final schedule plus real-time dispatch instructions; yet, using a unit's metered generation level instead of its AOT would be just another way of considering a unit's uninstructed energy (positive or negative) in the mitigated pricing methodology. *See* Exh. ISO-19 at 34:7-17.

Several subsidiary points bear noting. First, analysis conducted by one witness for sellers (Adamson) suggests that use of the AOT (in conjunction with monotonically non-decreasing incremental heat rates) tends to *increase* the incremental heat rate of the marginal unit in comparison to taking the heat rate at the metered operating point, *Id.* at 38:4-16 and n. 2; thus, use of the AOT may lead to *higher* mitigated prices and, to the extent it does, cannot be said to disfavor sellers. Second, implicit criticism of the AOT based on the need to "bound" AOT in some instances by a unit's physical operating limits (*see* Tr. 1549:3 – 1551:9) proves nothing other than that the ISO was careful in applying the AOT concept. Finally, while as a general rule use of metered operating levels is not justified, it may be appropriate to "screen out" units from eligibility to set the mitigated price based on their failure to deliver energy at all in response to dispatch instructions. Exh. ISO-19 at 39:6-15. *See generally* Section I.D.7, below.

D. What units are eligible to set the MMCP for each 10-minute interval in the refund period?

1. Is eligibility to set the MMCP contingent upon a unit having had a bid in the BEEP Stack?

<u>Proposed Finding:</u> Only gas-fired units that had a bid dispatched through the ISO's BEEP system, with the dispatch having been "acknowledged" by the units' operators, should be eligible to set the mitigated price for

each interval in which any gas-fired unit was dispatched through the BEEP system; for any interval in which no gas-fired unit was dispatched through the BEEP system, any gas-fired unit with a bid submitted into the BEEP stack is eligible to set the mitigated price.

Argument:

The methodology adopted by the Commission in the July 25 Order for determining the mitigated prices during the refund period is the same methodology adopted in the April 26 and June 19 Orders for determining the proxy market clearing price during periods of resource deficiency, except as that latter methodology was specifically modified by the Chief Judge in the Chief Judge's Report or by the Commission itself in the July 25 Order. The methodology for determining the proxy market clearing price during periods of resource deficiency requires the ISO to determine the marginal unit from among those gas-fired units with bids in the ISO's real time market, *i.e.*, the "BEEP stack." That aspect of the "forward-looking" methodology was not modified by either the Chief Judge or the Commission for purposes of determining mitigated prices during the refund period. Therefore, the universe of units eligible to set the mitigated price during the refund period is limited to gas-fired units that had bids in the BEEP stack.

There is no dispute, so far as the ISO is aware, that the methodology for determining the mitigated prices during the refund period is to be the same as the methodology for establishing proxy prices in times of resource deficiency, except as specifically modified by the Chief Judge or the Commission. In the Chief Judge's Report, the Chief Judge stated: "To re-create the outcome of a competitive market, the Chief Judge recommends that the methodology set forth in the June 19 Order be used with the modifications discussed below in order to calculate any potential refunds . . . ." 96 FERC at 65,039 – 65,040. Then, in the July 25 Order, the Commission stated: "We will adopt the recommendations of the Chief Judge, as modified below, and apply the methodology set out in the June 19 Order from the October 2, 2000, refund effective date, through June 20, 2001 to determine the amount of refunds due to the customers in the ISO and PX spot markets." 96 FERC at 61,516. The record could not be clearer that the "forward-looking" methodology of the June 19 Order applies to the refund period except as specifically modified.

Nor could the record be clearer that the "forward-looking" methodology of the June 19 Order establishes the universe of units eligible to set the proxy clearing price as those gas-fired units with bids in the ISO's real time market. The June 19 Order reaffirmed the methodology for setting proxy market clearing prices during periods of reserve deficiency that had been established in the April 26 Order; the change in the June 19 Order was to extend price mitigation to all hours (by adopting in non-reserve deficiency hours a maximum price equal to 85% of the proxy price in the last period of reserve deficiency). 95 FERC at 62,547 – 62,548. In the April 26 Order, the Commission had required the ISO to establish a proxy market clearing price in its real time market for periods of reserve deficiency. According to the Commission direction, the proxy price was to be based on the use of competitive bids (*i.e.*, bids based on marginal costs) from gas-fired units in order to replicate competitive pricing. *See* 95 FERC at 61,358.

Not only did the Chief Judge's Report and the Commission in the July 25 Order leave unchanged the requirement that clearing prices be based on units with bids in the real time market, they *expressly affirmed* that this was to be a feature of the methodology for determining mitigated prices during the refund period. Both the Chief Judge and the Commission made this express affirmation in the context of rejecting proposals by the ISO and others to mimic for the refund period the "must offer" requirement of the forward-looking mitigation plan. In rejecting application of the must-offer requirement to the refund period, the Chief Judge stated:

> The June 19 Order established a mitigated price based upon the marginal cost of the last unit dispatched to meet load in the CAISO's real-time market. The CAISO has the actual heat rate for every hour of *the last unit dispatched in the CAISO's real-time imbalance energy market*. The actual heat rates, rather than hypothetical heat rates (associated with recreating the must-bid requirement of the June 19 Order), provide the first step in calculating the cost of the marginal unit.

96 FERC at 65,040 (emphasis added). In other words, the Chief Judge recommended that the ISO use the heat rate of "the last unit dispatched in the CAISO's real-time imbalance energy market" as the "first step in calculating the cost of the marginal unit" during the refund period. The Commission was similarly explicit when it also rejected the concept of mimicking the "must offer" requirement during the refund period. First, the Commission characterized the June 19 Order as having "established a mitigated price based upon the marginal cost of the last unit dispatched to meet load in the ISO's real-time market." 96 FERC at 61,517. Then, in rejecting various parties' request that the Commission mimic the "must offer" requirement for the refund period, the Commission stated:

> We did not institute the must offer requirement or the marginal bidding requirement until May 28, 2001, and it is unreasonable to re-create the markets to apply such requirements for the period October 2, 2000 through June 20, 2001. Generators actually dispatched in the markets during these periods have specific marginal costs that are reasonably recovered under our methodology. The end result of using an assumed economic dispatch (prices lower than the actual marginal costs of the last generator dispatched) unfairly

> punishes the very generators that helped keep the lights on in California. Therefore, we will require that the ISO determine the last unit dispatched (the marginal unit) by selecting from the actual units dispatched in real-time *the maximum heat rate of any unit dispatched each hour in the real-time imbalance market for the period October 2, 2000 through May 28, 2001.*

Id. (emphasis added). In other words, the Commission, like the Chief Judge, expressly affirmed that the marginal unit for each interval was to be determined from among those units that had bids in the ISO's real time market.[9]

The only way for someone to contend that the Chief Judge and the Commission meant something other than that a unit must have had a bid in the BEEP stack is to argue that the phrases "real-time imbalance energy market" (used by the Chief Judge in his recommendations) and "real-time imbalance market" (used by the Commission in the July 25 Order) were intended to refer to something broader than the ISO's BEEP system. There is absolutely no basis for such an argument. Both the Chief Judge and the Commission are familiar with the ISO's energy and ancillary service markets. The only reasonable assumption is that they know that phrases such as "real-time imbalance energy market" and "real-time imbalance market" would be taken to refer to the *only* real time market for imbalance energy that the ISO runs, namely, the competitive auction market defined in the Tariff as the Real Time Market. *See* Exh. ISO-1 at 4:10-17 and n. 3. Generating units are dispatched in that market primarily in merit order of their bids through the BEEP system. *See Id.* at 5:12 – 6:8. Whenever the Chief Judge or the Commission referred to the "last unit dispatched" in the real time imbalance market, therefore, the reference could only be

[9] Because the stipulated issue in this section is whether a unit, to be considered, must have had a bid in the real time market, that is the way we are arguing the point in this section – *i.e.*, that a unit need only have had a bid in the BEEP stack. Note, however, that both the Chief Judge and the Commission were clear that for the refund period, a unit must not only have had a bid in the BEEP stack, but also must have been

to the single market operated by the ISO. The ranking of bids within the BEEP system in order to create a supply curve is referred to as the "BEEP stack." *Id.* at 7:21 – 8:17. It is clear, therefore, that to be eligible to set the mitigated price, a unit must have had a bid in the BEEP stack.

2. Are the following energy types eligible to set the MMCP?

a. BEEP Supplemental?

Proposed Finding: Gas-fired units with supplemental energy bids dispatched through the BEEP system should be eligible to set the mitigated price for an interval.

Argument:

Supplemental energy bids are bids offering to provide energy from capacity that is uncommitted entering an interval, based on final schedules, or bids offering to decrease generation in real time (*i.e.*, decremental bids). Supplemental energy bids are one type of bid that is available for dispatch through the BEEP system. *See* Exh. ISO-1 at 6:15 – 7:2. The ISO's position is that a unit, to be eligible to set the mitigated price during the refund period, must not only have had a bid in the BEEP stack, but must also have been dispatched through the BEEP system. *See* section I.D.2.c, below.

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dispatched in the real time market in order to be eligible to set the mitigated price. This point becomes important in subsequent sections of the brief, *e.g.*, I.D.2.c, d, and e.

b. BEEP Spin, Non-spin and Replacement A/S?

<u>Proposed Finding:</u> Gas-fired units with energy bids associated with spinning, non-spinning and replacement reserves that were dispatched through the BEEP System should be eligible to set the mitigated price for an interval.

<u>Argument:</u>

From the joint narrative stipulation of issues, there appears to be no dispute on this point. Any time a unit's operator bids the unit's capacity into the ISO's ancillary services markets to provide spinning reserves, non-spinning reserves or replacement reserves, the operator must also submit a bid for the energy associated with those reserves. Those energy bids are the other type of bid (in addition to supplemental energy bids, discussed above) that is available for dispatch through the BEEP system. *See* Exh. ISO-1 at 6:12 – 7:2. The ISO's position is that a unit, to be eligible to set the mitigated price during the refund period, must not only have had a bid in the BEEP stack but must also have been dispatched through the BEEP system. *See* section I.D.2.c, below.

c. OOS Non-congestion Imbalance Energy Supplemental?

<u>Proposed Finding:</u> Units with supplemental energy bids in the BEEP system that were dispatched out-of-sequence by the ISO outside of the BEEP system should not be eligible to set the mitigated price for an interval.

<u>Argument:</u>

This question and the two following questions refer to units with energy bids in the BEEP stack that were dispatched by the ISO "out-of-sequence" for various reasons. In addressing these three questions, the ISO is interpreting the phrase "out-of-sequence" to mean that units had bids submitted to the ISO's real time market, but were dispatched *outside of the BEEP system*, and paid on an "as-bid" basis. The ISO did not consider such units eligible to set the mitigated price, because historically they had not been used by the BEEP system to calculate the market clearing price for an interval. *See* Tr. at 1335:10-17; 1345:14-16; 1347:23 – 1348:7; 1353:9 – 1360:18. The ISO takes the same position with respect to all out-of-sequence dispatches made outside of the BEEP system. As a consequence, we will state that position here and refer back to this section instead of repeating the argument under the next two sections.

The ISO's position is that any unit dispatched out-of-sequence outside of the BEEP system, and therefore not used in the calculation of the market clearing price for an interval, should be excluded from eligibility to set the mitigated price.[10] The fundamental reason is that the ISO interprets the relevant Commission orders to specifically restrict the units eligible to set the mitigated price to those units with bids in the BEEP stack that were actually used in setting the market clearing price in the ISO's real time market when they were dispatched.

The key portion of the July 25 Order is the sentence in which the Commission stated that "we will require that the ISO determine the last unit dispatched (the marginal unit) by selecting from the actual units dispatched in real time the maximum heat rate of any unit dispatched each hour *in the real-time imbalance market* for the [refund period]." 96 FERC at 61,517 (emphasis added). The Commission in that sentence described two different groups of units – those "dispatched in real time"

[10] The ISO would exclude from eligibility only the portion of a unit's output that was called out-of-sequence. This means that a unit with some output dispatched out-of-sequence could be eligible to set the

and those “dispatched each hour in the real-time imbalance market.” The latter group is a sub-set of the former: while units are dispatched in many ways and for many reasons in real time, only *certain* of those units are dispatched “in the real-time imbalance market.” It was the maximum heat rate of any unit in that latter, smaller group of units that the Commission intended the ISO to use to calculate the mitigated price.[11]

The units that the ISO dispatches “in the real-time imbalance market” are *only* those units that are dispatched through the ISO’s BEEP system. *See* Exh. ISO-1 at 5:12 – 6:8. That market is described in the Prepared Direct Testimony of Dr. Hildebrandt, Exhibit ISO-1, at 7:19 – 9:17. In brief summary, that market operates as follows: the BEEP system ranks all supplemental energy bids and bids for energy associated with ancillary services in merit order by price to create a supply curve; the ISO’s generation dispatchers then dispatch these bids in merit order, to the extent possible (given different system and resource-specific constraints), either for increases in supply (“incremental bids”) or for decreases in supply (“decremental bids”) to balance supply and demand in each 10-minute interval. Bids deemed eligible to set the market clearing price are dispatched through the BEEP system, which automatically issues dispatch instructions and records the amount of bids dispatched from each unit. The market clearing prices for incremental and decremental supply are then determined based on the last bid dispatched form the marginal unit, *i.e.*, the highest priced incremental bid or lowest priced decremental bid

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mitigated price if some of its output also was dispatched through the BEEP software, but it would be eligible only at the output level that reflects that dispatch. *See* Exh. ISO-1 at 45:16 – 46:6.

[11] The Commission’s directive that the ISO use the maximum heat rate of any unit dispatched in the real time imbalance market echoed the Chief Judge’s recommendation that the ISO, in calculating the mitigated price, start with the heat rate of “the last unit dispatched in the CAISO’s real-time imbalance energy market.” 96 FERC at 65,040.

dispatched to balance supply and demand (the "marginal resource"). Those market clearing prices are earned not only by all units dispatched through the BEEP software in an interval but also by units that over- or under-generate in an interval without instructions from the ISO (so-called "uninstructed deviations" that produce "uninstructed energy"). However, *only* the bids dispatched through the BEEP software are dispatched "in the real time imbalance market" and only those bids are eligible to set that market clearing price. *Id.* at 43:16 – 45:2.

Units with bids in the BEEP stack can be dispatched out-of-sequence, *i.e.*, out of merit order, *outside of the BEEP system* in order to meet some local or other reliability problem. Although these bids are dispatched, they have not been dispatched "in the real time imbalance market," and they are not eligible to set the market clearing prices under the ISO Tariff. The owners or operators of units dispatched out-of-sequence outside of the BEEP system are paid their bid price, not the market clearing price. *See* Exh. ISO-1 at 13:1-13. When the Commission directed the ISO to determine the marginal unit dispatched "in the real time imbalance market," the ISO interpreted the Commission as having intended the ISO's usual understanding of that term under its tariff. Therefore, the ISO has excluded from consideration bids dispatched out-of-sequence if those bids were dispatched outside of the BEEP system and thus were not among the bids actually used in setting the "historical" market clearing price in the real time market. This is perfectly consistent with the way the ISO has implemented the Commission's directive in the April 26 and June 19 Orders to determine mitigated prices in periods of reserve deficiency; the ISO has made its practice of excluding this category of out-of-sequence dispatches clear in its compliance filings, and the Commission has not indicated any disagreement. Exh. ISO-1 at 50:6 – 52:22. In fact, the Commission recently accepted this aspect of the compliance filings. *See* Compliance Order, *supra.*

In distinction to the treatment of units with bids dispatched out-of-sequence outside of the BEEP System, the ISO has made clear that units with bids dispatched out-of-sequence *through the BEEP system* (and therefore allowed to set the actual market clearing price in the real time market) should be considered in setting the mitigated price. *See* Tr. at 1353:9 – 1360:18. The ISO's analysis includes *all* gas-fired units with bids dispatched through the BEEP system, as recorded in the "BEEP output" file, including units dispatched out-of-sequence through the BEEP system. *See Id.;* 1335:2-5. The BEEP output file represents the complete set of dispatches actually used by the BEEP system in determining the market clearing price for an interval. *See* Tr. at 1353:9 –1360:18; 1401:24 – 1402:3. Records of automated BEEP dispatches contain no indicator of which units were dispatched out-of-sequence, but were nonetheless dispatched through the BEEP system so that their bids were eligible to set the market clearing price. *See* Tr. at 1358:6-20. Thus, the "out-of-sequence" dispatches referenced in the testimony of sellers' witnesses represent a sub-set of all units that were dispatched out-of-sequence; that subset consists only of those out-of-sequence bids that were dispatched *outside of the BEEP system* and were therefore recorded manually in other databases by generation dispatchers. That subset should not be considered in setting the mitigated price.

d. OOS Non-congestion Imbalance Energy Spin, Non-Spin and Replacement A/S?

<u>Proposed Finding:</u> Units with bids in the BEEP system that were dispatched out-of-sequence by the ISO outside of the BEEP system should not be eligible to set the mitigated price for an interval.

<u>Argument:</u>

See section I.D.2.c, above.

e. OOS Congestion?

<u>Proposed Finding:</u> Units with bids in the BEEP system that were dispatched out-of-sequence by the ISO outside of the BEEP system should not be eligible to set the mitigated price for an interval.

<u>Argument:</u>

See section I.D.2.c, above.

f. OOM?

<u>Proposed Finding:</u> Units with no bids in the BEEP system, which were dispatched out-of-market by the ISO, should not be eligible to set the mitigated price for an interval.

<u>Argument:</u>

Under section I.D.1, above, we have explained that the Commission's July 25 Order requires that a unit must have had a bid in the BEEP stack in order to be eligible to set the mitigated price. (Moreover, under section I.D.2.c, above, we have explained that under the Commission's order not even all units with bids in the BEEP stack are eligible, but only those that are dispatched by the BEEP software, and thus "dispatched in the real time imbalance market.") The requirement that a unit have had a bid in the BEEP stack excludes units called "out of market" from eligibility to set the mitigated price, as the very definition of an out-of-market call is that the unit or other resource being called on did *not* have a bid in the BEEP stack. Exh. ISO-1 at 13:16 – 14:7. The ISO may issue out-of-market calls to resources both within and outside of the ISO's control area, in order to ensure system reliability. The ISO frequently calls units out-of-market well ahead of a specific interval, even a day or more ahead, requiring them to be on at minimum load in order to be available to provide additional energy quickly if needed. For generating units within the control area, the owner or operator is paid either the market clearing price for incremental energy as determined in the real-time imbalance market, or a cost-based payment, depending upon the before-the-fact choice by the owner or operator. When calls are made outside the control area, the ISO negotiates a price *ad hoc*, and does not know the specific generating unit providing the energy. During the refund period, only 8% of the energy purchased out-of-market came from gas-fired generating units within the control area. *See* Exh. ISO-1 at 14:7 – 15:16; 48:16 – 49:21.[12]

g. Residual Energy?

<u>Proposed Finding:</u> Units providing energy in an interval as a result of ramping constraints, *i.e.*, units dispatched in previous intervals but not in the

[12] A unit called out-of-market may also subsequently be dispatched through the ISO's BEEP system. For example, if the unit is called ahead of an operating interval to be on at minimum load, the owner or operator may then bid additional energy into the real-time imbalance market, and be dispatched for that additional energy. In this situation, the ISO did include the unit among those eligible to set the mitigated price for the interval in which it was dispatched through the BEEP software, but only at the operating level represented by the BEEP dispatch. Exh. ISO-1 at 49, n. 6.

specific interval under consideration, should not be eligible to set the mitigated price for the interval under consideration.

Argument:

Residual imbalance energy is energy provided by a generating unit in one interval as a result of a dispatch instruction issued to that unit in a previous interval. Residual imbalance energy is a result of the operating characteristics of generating units: when the ISO dispatches a unit with a bid in one interval but does not “re-dispatch” that unit in immediately following intervals, the unit may still produce energy in those following intervals because its ramp rate is such that it cannot “shut down” immediately. Under the ISO’s settlement process, residual imbalance energy is compensated at the market clearing price for the interval in which the ISO last dispatched the unit. The residual imbalance energy is not considered at all in determining the market clearing prices for the subsequent intervals. *See* Exh. ISO-1 at 10:12 – 11:2.

As an example, assume unit *a* is dispatched at 100 MWs for interval *x* and is not dispatched for the subsequent intervals *y* and *z*, even though its owner or operator had bids in the BEEP stack for those subsequent intervals, but unit *a* still produces 60 MWs in interval *y* and 20 MWs in interval *z* due to the ramping constraints of the unit. The bid covering the 100 MWs is considered in setting the market clearing price for interval *x* but not for intervals *y* and *z*; any bids the owner or operator of unit *a* might have in the BEEP stack for intervals *y* and *z* are not considered in determining the market clearing prices for those intervals; and the owner or operator is compensated at the market clearing price set in interval *x* for all 180 MWhs produced during intervals *x, y* and *z* (100 + 60 + 20).

In the intervals in which a unit is producing residual imbalance energy, that unit has not been "dispatched in the real-time imbalance market;" rather, it is still producing energy due to having been dispatched in the real-time imbalance market for one or more previous intervals. Therefore, under the July 25 Order, the unit should not be considered as eligible to set the mitigated price in all previous intervals in which it is producing imbalance energy (although it would be considered as eligible to set the mitigated price in the previous interval or intervals in which it had been dispatched). *See* Exh. ISO-1 at 46:17-22.

h. Regulation?

<u>Proposed Finding:</u> Units providing energy from regulation service should not be eligible to set the mitigated price for an interval.

<u>Argument:</u>

Regulation service is an ancillary service that is bid into and awarded in the ISO's day-ahead and hour-ahead markets for ancillary service. Units providing regulation service can be automatically ramped up or down very quickly at the ISO's request, within certain ranges (*i.e.*, they are on "automated generation control" or "AGC"). The ISO does not order these units up or down in any merit order; rather, it obtains more or less energy from them as it deems best for managing or "fine tuning" system conditions. In the settlement process, energy provided from regulation service is treated as "price taker" energy and is paid the market clearing price as determined in the ISO's competitive real-time market. *See* Exh. ISO-1 at 11:4-21.

From this description, one sees that energy from regulation service is not dis-patched "in the real-time imbalance market." Instead, it is dispatched completely outside that market, but receives whatever price is determined by those units that *are* dispatched in that market. Under the July 25 Order, therefore, units providing energy from regulation service during an interval should not be eligible to set the mitigated price. *See* Exh. ISO-1 at 47:1-5.

i. Other Imbalance Energy?

Proposed Finding: Units providing energy in real time as a result of reliability must-run ("RMR") dispatches, scheduling through the California Power Exchange ("PX"), bilateral arrangements, or the provision of uninstructed imbalance energy, should not be eligible to set the mitigated price.

Argument:

RMR units are units under contract with the ISO to provide energy (and ancillary service) when called upon (under terms of the contract) to ensure the reliability of the system. Without the contractual obligation to provide energy when called upon, these units could exercise market power due to their being essential at times to ensure that reliability. The ISO normally calls upon these units ahead of real time, in which case the energy required by the ISO must be bid into the real time imbalance market at a bid of zero. In addition, the ISO may issue dispatch notices to these units to change their operating levels in real time. In both circumstances, *i.e.*, whether the unit is called ahead of real time or in real time, the owner or operator of an RMR unit may elect to receive either the real time market clearing price as determined by the other (*i.e.*, non-RMR) bids in the real time imbalance market, or a pre-determined price based on the RMR unit's variable operating costs. *See* Exh. ISO-1 at12:1-22. While RMR units therefore are sometimes dispatched by the ISO in real time, the energy called upon by the ISO under the RMR contract is always bid into the real time imbalance market at a price of zero and thus these bids are not eligible to set the market clearing price. Because bids covering RMR energy could not set the market clearing price historically, RMR units should not be considered eligible to set the mitigated price for the refund period to the extent they were providing RMR energy. In addition, the energy from RMR units is being provided to meet a local reliability need, not to meet overall demand in the system; therefore, an RMR unit, when it was providing energy under the RMR contract, was never the "last unit dispatched" to meet demand, and cannot be the marginal unit. Exh. ISO-1 at 47:13 – 48:14.

A unit that provides uninstructed imbalance energy not only has not provided energy pursuant to an ISO dispatch instruction; it has provided energy *contrary to* such a dispatch instruction. "Uninstructed" imbalance energy is just what the name implies – energy that a unit provides in real time without having been instructed by the ISO to do so. This energy is not the result of merit order dispatch of system resources (in fact, its provision may require the ISO to *back down* other resources that had been dispatched in merit order). While the energy (in the case of a positive uninstructed deviation) or the decreased generation (in the case of a negative uninstructed deviation) is paid in the settlement process based on the market clearing prices in the real time imbalance market, the energy or decrease in generation plays no part in determining those market clearing prices. There would be no justification for allowing these deviations from forward schedules or from ISO dispatch instructions to be eligible to be the marginal unit of supply dispatched by the ISO. *See* Exh. ISO-1 at 15:18 – 16:20; 49:21 –50:4.

Units that provide energy in real time as the result of bids having been accepted in the PX forward markets, or as a result of bilateral contractual arrangements, are not providing imbalance energy at all. Rather, they are providing energy as a result of forward schedules submitted to the ISO, which are the schedules that the ISO takes into account in determining the amount of imbalance energy that it will be necessary to purchase in real time. Units that are operating pursuant to such forward schedules not only are not "dispatched" by the ISO in the "real time imbalance market," they are not dispatched by the ISO in real time *at all*. Therefore, there can be no justification for these units to be eligible to determine the "last unit dispatched." *See* Exh. CAL-21 at 14:16 – 15:7.

3. If eligibility of a unit is contingent upon having had a bid in the BEEP Stack, what approach to eligibility should be taken during intervals in which there were incremental dispatch instructions from the BEEP Stack?

Proposed Finding: For an interval in which at least one gas-fired unit was dispatched by the BEEP software to provide incremental energy, the marginal unit should be chosen from all gas-fired units so dispatched, with the marginal unit being the unit with both an acknowledged dispatch instruction and the highest marginal operating costs.

Argument:

The issue in this situation is whether only gas-fired units that received dispatch instructions for incremental energy should be eligible to set the mitigated price, or whether gas-fired units (if any) that received decremental dispatch instructions during the same interval should also be considered eligible. The ISO has considered only gas-fired units with incremental dispatch instructions in these circumstances. *See* Exh. ISO-1 at 33:15-20; ISO-16 at 4:13 – 5:2.

The ISO submits there are three reasons that only gas-fired units with incremental dispatch instructions should be eligible in these circumstances. First, considering only units with incremental dispatch instructions is called for by the language of the directly controlling Commission orders, which speak in terms of the "last unit dispatched to meet load." *See, e.g.*, 97 FERC at 62,178, 62,192. Only units dispatched to provide incremental energy are dispatched "to meet load" as that phrase is commonly understood. *See* Exh. ISO-19 at 43:7-13; 46:20 – 47:6. Second, under the ISO Tariff, in intervals in which there are incremental dispatch instructions, only bids of units that receive such instructions are considered in determining the market clearing price for incremental energy; thus, the ISO's methodology for determining the marginal unit during the refund period is consistent with the Tariff. *Id.* at 45:10-14. Finally, the ISO has been determining the proxy prices during periods of reserve deficiency in this way since its first compliance filing pursuant to the April 26 Order, with no indication from the Commission that it disapproved of this approach. *Id.* at 50:22 – 51:6. Since neither the Chief Judge in his recommendations nor the Commission in the July 25 Order and the December 19 Order on Clarification and Rehearing suggested there should be any difference between the "forward-looking" mitigation methodology and refund methodology in this area, the ISO's unchallenged use of this method for the forward-looking mitigation indicates the same methodology is acceptable for the refund period.

4. If eligibility of a unit is contingent upon having had a bid in the BEEP Stack, what approach to eligibility should be taken during intervals in which there were decremental dispatch instructions, but not incremental dispatch instructions, from the BEEP Stack?

__Proposed Finding:__ **For an interval in which no gas-fired unit was dispatched by the BEEP software to provide incremental energy, but at least one gas-fired unit received a decremental dispatch instruction, the marginal unit should be chosen from all gas-fired units so dispatched, with the marginal unit being the gas-fired unit with both an acknowledged dispatch instruction and the lowest marginal operating costs.**

__Argument:__

The approach set forth in the proposed finding is the one followed by the ISO. *See* Exh. ISO-1 at 34:16 – 35:3; ISO-16 at 5:10-20. The ISO submits that the same three reasons given in the previous section also support the ISO's methodology in these circumstances. First, this methodology is most consistent with the relevant language of the Commission orders. The orders seem to have been drafted with the situation of incremental dispatch instructions in mind, and do not expressly address the situation of an interval in which no gas-fired unit received an incremental dispatch instruction. *See* Exh. ISO-19 at 49:1 – 50:10. Nevertheless, since there were intervals in which no gas-fired unit was incremented, some methodology must be devised for those intervals that is consistent with the Commission's language. The ISO's methodology does determine the "last unit dispatched" in these intervals: when only decremental dispatches are issued, the "last unit dispatched" is the unit with the lowest decremental bid, and determining the unit with the lowest marginal costs among those decremented units mimics that approach. *Id.* at 50:4-20. Second, the ISO's approach follows the way in which the price for *incremental* energy is determined under the ISO Tariff when only decremental dispatches are issued: the price for incremental energy (to be paid to units with uninstructed incremental deviations, for example) is determined by the lowest decremental bid that is dispatched. *Id.* at 47:17 – 48:4; *see also* Exh. ISO-1 at 37:7 – 38:8 (discussing lowest "heat rate" instead of lowest "marginal cost," as testimony was written before the December 19 Order on Clarification and Rehearing). Finally, the ISO has consistently followed this methodology in determining proxy prices during periods of reserve deficiency since its first compliance filing pursuant to the April 26 Order without any challenge by the Commission; since neither the Chief Judge nor the Commission in the July 25 Order and the December 19 Order on Clarification and Rehearing suggested any distinction between the forward-looking mitigation and mitigation during the refund period in this area, the same approach should be taken for the refund period. *Id.* at 50:15 – 51:6.

5. What approach to determining the unit that sets the MMCP should be taken during intervals in which no eligible unit was dispatched for imbalance energy?

Proposed Finding: **For an interval in which no gas-fired unit received either an incremental or a decremental dispatch instruction issued in merit order by the BEEP software, the marginal unit should be the gas-fired unit with the lowest marginal operating costs that had a bid in the BEEP system.**

Argument:

The July 25 Order and the December 19 Order on Clarification and Rehearing require the ISO to base the mitigated price on the marginal costs of the "last unit dispatched to meet demand" in an interval. *See* section III.D.5, above. Neither order addresses the approach to be taken in an interval in which no gas-fired unit was dispatched. Nevertheless, a mitigated price must be calculated for these intervals, in order to mitigate prices paid to other units that were dispatched, to marketers, and to uninstructed energy. The ISO believes that the approach most consistent with the intent of the Commission's orders is to take the gas-fired unit with the lowest marginal costs that had a bid in the BEEP stack during these intervals. Dr. Hildebrandt explained the reasoning as follows:

> Under the ISO's Tariff, the ISO accepts bids for incremental Imbalance Energy in economic merit order (in ascending order of price). Thus, for purposes of determining the marginal gas unit for those intervals in which no gas-fired unit was dispatched in the ISO's Real Time Market, the lowest incremental heat rate of gas units with bids into the ISO's Real Time Market represents the best indication of the marginal gas unit that could be dispatched to meet demand, since this unit could have been called on first by the ISO's BEEP system had there been a need for incremental Imbalance Energy. This approach reflects how the ISO's BEEP software is designed to calculate the incremental MCP for Real Time Energy in the event that no units are dispatched through BEEP during any interval. This approach is also consistent with the standard economic principles that (1) marginal costs are the costs of producing one unit more (or less) and (2) under competitive market conditions, market clearing prices in uniform price auctions should equal the marginal costs of the last increment of supply needed to meet demand.

Exh. ISO-1 at 38:21 – 39:14. *See also* Exh. ISO-16 at 6:17 – 7:10.

6. Should units running on fuels other than natural gas be eligible to set the MMCP?

<u>Proposed Finding:</u> A unit should not be eligible to set the mitigated price during any interval in which that unit was not running on natural gas.

<u>Argument:</u>

This finding was stipulated by the parties. *See* Exh. J-1.

7. Should units that did not show positive or negative responses to BEEP Stack dispatch instructions be eligible to set the MMCP?

<u>Proposed Finding:</u> If a unit that did not respond to an incremental or decremental dispatch instruction issued by the BEEP software, it should not be eligible to set the mitigated price (in future calculations of the mitigated price).

<u>Argument:</u>

In calculating mitigated prices, the ISO adhered strictly to the use of AOTs (*see* section I.C, above) without *any* reference to actual metered data. As a result, a generating unit that *did not respond at all* to an ISO dispatch instruction was nevertheless eligible to set the mitigated price for an interval. Exh. ISO-1 at 27:16-19; 29:1 – 33:4; CAL-1 at 8-15. Dr. Stern, a witness for the California Parties, determined that in many instances the unit the ISO had determined to be the marginal unit had not, in fact, responded at all to the ISO's dispatch instruction; he suggested a screen of whether a unit had changed its output at least 0.1 MW in response to the ISO's instruction, before including the unit in the universe of units eligible to set the mitigated price. Exh. CAL-1 at 21:15 – 24:10. Dr. Stern reasoned that "the marginal cost of a generating unit that did not respond to an ISO dispatch instruction is irrelevant to the determination of the marginal cost of energy in the Imbalance Energy market." *Id.* at 22:15-19. In his Prepared Rebuttal Testimony, Dr. Hildebrandt, on behalf of the ISO, acknowledged that such a screen could be appropriate:

> Specifically, it may be appropriate to utilize metered generation levels to "screen out" units that did not deliver energy pursuant to dispatches (i.e., making them ineligible to set the mitigated price for that interval). This adds some complexity to the analysis, but provides a more reasonable indication of the marginal gas-fired unit dispatched to meet demand in the Real Time Market that actually helped to "keep the lights on."

Exh. ISO-19 at 39: 9-15. In his Prepared Rebuttal Testimony, Mr. Sammon, on behalf of FERC Staff, agreed with Dr. Stern that a unit that failed to respond to an ISO dispatch instruction should be ineligible to set the market clearing price. Exh. S-26 at 43:4-13. Mr. Sammon pointed out that this approach would be consistent with the ISO Tariff, which "states that if a unit fails to respond to an ISO dispatch instruction, that unit's bid cannot set the BEEP stack clearing price." *Id.* at 57:2-6. The ISO's position is that a unit that did not respond measurably to an ISO dispatch instruction (*e.g.*, did not change its output level at least 0.1 MW, as suggested by Dr. Stern) may appropriately be screened out of consideration in determining the mitigated price for an interval.

8. Should units outside the ISO control area be eligible to set the MMCP?

<u>**Proposed Finding:**</u> **Units outside the ISO control area should not be eligible to set the mitigated price.**

<u>**Argument:**</u>

In calculating the mitigated price, the ISO excluded units outside the ISO control area for two reasons. The first was that the ISO's basic methodology was to consider only units that were eligible to set the market clearing price in the ISO's real time imbalance market, and only units within the control area (*and* that have executed Participating Generator Agreements ("PGAs")) are eligible to set the market clearing price in that market. The second reason was practical: the ISO cannot identify the individual unit that is the source of any bid that comes from outside the control area (or even a bid from inside the control area but based on units without PGAs). *See* Exh. ISO-1 at 40:13-22. In the December 19 Order on Clarification and

Rehearing, the Commission clarified that imports (any resource from outside the ISO control area is treated as an import) may not set the mitigated price for the refund period, as any attempt to factor in heat rates from such resources would be "extremely speculative." 97 FERC at 62,202.

E. Additional Issues Related to the MMCP Calculation.

1. What is the proper use of gas price indices for the calculation of the MMCP for each interval?

Proposed Finding: The gas price used in calculating the mitigated price should be the average of the published midpoint daily spot gas prices reported in the publications required by the Commission to be used for the northern and southern zones.

Argument:

The dispute concerning gas indices is over whether to use the "midpoint" of daily spot gas prices, as the ISO did and as California Parties and California Generators agree is correct, or the "common high" index, as advocated by witnesses for several sellers. The ISO submits that a straightforward reading of the Commission's July 25 Order compels the use of the midpoint and that using the midpoint makes sense.

In the July 25 Order, the Commission stated that it was adopting the recommendations of the Chief Judge for calculating mitigated prices during the refund period, except as those recommendations were specifically modified by the Commission. 96 FERC at 61,516. With respect to gas prices, the Chief Judge had recommended departing from the use of monthly bid-week prices averaged for three delivery points, which were the prices to be used under the Commission's June 19 Order for calculating proxy market clearing prices in times of resource deficiency. The Chief Judge recommended the use of daily spot gas prices for certain delivery points in northern and southern California, respectively, in calculating mitigated prices during the refund period. The Chief Judge stated: "The daily spot gas prices should be for the 'midpoint' as published in Financial Times Energy's 'Gas Daily' publication for the aforementioned delivery points." 96 FERC at 65,040. The Commission in the July 25 Order stated that it was "adopting the Chief Judge's recommendation to use daily spot gas prices and the three delivery points. . . ." but with "one modification." 96 FERC at 61,518. That "one modification" was to require use of three publications as sources of data, instead of one. The Commission concluded: "Accordingly, *the gas inputs recommended by the Chief Judge* should be based on the simple average daily spot price as reported by" the three publications. *Id.* (emphasis added). The key points are that (a) the Commission made only "one modification" to the Chief Judge's recommendation, which was to increase the number of sources of data, and (b) the Commission explicitly concluded that the mitigated price calculations should use the "gas inputs recommended by the Chief Judge." The "inputs" recommended by the Chief Judge were the "midpoint" of the daily spot gas prices, not the "common high."

Common sense also compels the use of the midpoint. There is no reason to assume that the operator of the marginal unit for every interval will always pay the "high" price for daily spot gas. One must remember that using a daily spot gas price index already incorporates the concept that purchases are being made at the last minute. Intuitively, one would expect that the operators of the marginal units sometimes would pay the "high" price and sometimes the "low" price and sometimes a price between the two. In other words, one intuitively concludes that over the entire refund period, the "midpoint" should be a good approximation of the average spot price paid by the operators of marginal units. *See* Exh. ISO-20 at 15:19 – 16:13.

2. To the extent hourly MMCPs are calculated based upon 10-minute interval MMCPs, should the interval MMCPs be averaged on a weighted or simple average basis?

Proposed Finding: Hourly mitigated prices should be developed by taking the simple average of the mitigated prices for the intervals.

Argument:

To obtain the simple arithmetical average of the intervals within an hour, one sums the prices calculated for the six intervals (*i.e.*, the total operating costs of the marginal units for the six intervals, determined by the formula in section I.A, above) and divides by six. This is the most straightforward implementation of the Commission's directive that the ISO "take the average of the maximum heat rates for the six ten-minute periods in order to develop a market clearing price for application to the hourly auctions (including the PX markets)." July 25 Order, 96 FERC at 61,517, n. 68. *See* Exh. ISO-1 at 55:13-22; *see also* S-26 at 42:3 – 43:3 ("average" implies simple average unless Commission instructs otherwise). Using the simple average is also consistent with basic mathematical principles. For products priced and delivered on an hourly basis (*e.g.*, energy sold into the PX's forward markets, or ancillary services sold into the ISO's forward markets), the quantity delivered in each 10-minute interval is the same. Therefore, the *weighted* average of the prices for the 10-minute intervals is the *same* as the *simple* average of the prices for the six 10-

minute intervals, but that average is *different from* the weighted average of prices for products that are delivered and sold on the basis of 10-minute intervals. This concept is fully explained and illustrated in Exh. ISO-19 at 61:4 – 64.

3. Is there a separate formula for calculating MMCPs for ancillary services and, if so, what is it?

Proposed Finding: **[This issue has been deferred until the hearing on Issues 2 and 3.]**

CONCLUSION

For the reasons stated herein, the ISO requests that the Presiding Judge make the findings proposed in this brief.

Respectfully submitted,

Charles F. Robinson
Vice President/General Counsel
Gene Waas, Regulatory Counsel
California Independent System
Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630
Tel: (916) 608-7144
Fax: (916) 608-7296

J. Phillip Jordan
Michael Kunselman
Swidler Berlin Shereff Friedman, LLP
3000 K Street, NW, Suite 300
Washington, DC 20007
Tel: (202) 424-7500
Fax: (202) 424-7643

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