**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL REGULATORY ENERGY COMMISSION**

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

**Answer of the California Independent**
**System Operator Corporation to Motions to Intervene,**
**Requests for Clarification, Comments and Protests to the**
**July 10, 2001 Compliance Filing and Proposed Tariff Amendments**

On July 10, 2001, the California Independent System Operator Corporation ("ISO")[1] submitted a compliance filing and proposed Tariff revisions ("July 10 Compliance Filing") as directed in the Commission's June 19, 2001 "Order on Rehearing of Monitoring and Mitigation Plan for the California Wholesale Electric Markets, Establishing West-wide Mitigation, and Establishing

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

Settlement Conference" ("June 19 Order")[2] in the above-referenced docket. In the July 10 Compliance Filing, the ISO not only submitted the Tariff revisions needed to comply with the June 19 Order, but also described in detail the ISO's implementation procedures for the modified market mitigation plan established by the June 19 Order, including facilitation of the must-offer obligation, development of proxy and Market Clearing Prices, and the processes for justification of bids and the collection of charges for and payment of emission and start-up costs. The Commission's July 16, 2001 Notice of Filing directed parties to comment on the ISO's Compliance Filing on or before August 9, 2001.

Pursuant to Rule 213 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213, the ISO submits its Answer to the motions to intervene, requests for clarification, comments and protests concerning the July 10 Compliance Filing in the above-captioned docket. The ISO does not oppose the intervention of any party that sought leave to intervene in this proceeding. As explained below, however, the comments and protests that seek the rejection or substantive modification of the ISO's July 10 Compliance Filing are without merit except where the ISO has agreed to make one modification in response to a request for clarification of its filing. The Commission should accept the ISO's proposed Tariff revisions without condition and with only such minor modifications as the ISO agrees to below.

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[2] 95 FERC ¶ 61,418 (2001).

## I. BACKGROUND

In its December 15, 2000, Order,[3] the Commission found that the market structures and rules for wholesale markets in California were seriously flawed and mandated various remedies to address these circumstances, including the establishment of a $150/MW "soft cap" in the ISO's Ancillary Services and real-time Imbalance Energy markets and the ability of sellers to be paid their bid price (i.e., paid "as bid") above the $150/MW soft cap. The December 15 Order also required the development of a longer-term mitigation plan to replace the interim breakpoint methodology. On April 26, 2001, the Commission issued its "Order Establishing Prospective Mitigation and Monitoring Plan for the California Wholesale Electric Markets and Establishing an Investigation of Public Utility Rates in Wholesale Western Energy Markets" in the above-captioned dockets ("April 26 Order").[4] In the April 26 Order, the Commission reaffirmed its previous findings that there is a potential for the exercise of market power in the California wholesale markets under certain conditions and mandated that a replacement mitigation plan be put into place. The primary elements of the April 26 Order's mitigation plan included:

- a requirement for all sellers, including non-public utilities, that own or control generation (with the exception of hydroelectric facilities) in California to offer all of their available generation to the ISO's real-time energy market;
- a price mitigation mechanism for the ISO's real-time energy market during System Emergencies;

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3 *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,* et al., 93 FERC ¶ 61,294 (2000)("December 15 Order").

4 95 FERC ¶ 61,115 (2001).

- provision for refund liability and conditions on public utility sellers' market-based rate authority to prevent anti-competitive bidding behavior; and

- increased coordination, control and reporting of outages.

In compliance with the April 26 Order, the ISO filed, on May 11, 2001, Tariff revisions to implement: 1) proxy price calculation, reporting and cost-justification provisions; 2) data requirements for the ISO's implementation of generators' must-offer obligation; and 3) expanded outage coordination procedures ("May 11 Compliance Filing").[5]

On May 18, 2001, the ISO filed a Status Report in the above-captioned proceeding to update the Commission on the ISO's progress towards implementation of the April 26 Order, to describe the ISO's plans to implement various aspects of the April 26 Order ("May 18 Status Report"). In the May 18 Status Report, the ISO requested guidance on various implementation issues, including the appropriate treatment of generators that had not provided information requested by the ISO and needed for the ISO to implement and monitor the "must-offer" and price mitigation aspects of the April 26 Order. The ISO also requested that the Commission immediately advise the ISO of any necessary modifications to the ISO's plan to implement the April 26 Order.

On May 25, 2001, the ISO filed a second Status Report in the above-captioned proceeding to update the Commission on the ISO's progress towards

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[5] The Commission issued a May 15, 2001 Notice of Filing in this proceeding directing parties to comment on the ISO's May 11 Compliance Filing of proposed Tariff revisions on or before May 22, 2001.

implementation of the April 26 Order ("May 25 Status Report"). In the May 25 Status Report, the ISO described the progress of its efforts to develop and test the software needed to implement aspects of the April 26 Order, described certain assumptions the ISO intended to utilize in determining the "proxy price" to be calculated pursuant to the April 26 Order, and noted the continued non-compliance of a number of generators with requests for the information needed to implement the April 26 Order. The ISO again requested that the Commission immediately advise the ISO of any necessary modifications to the ISO's plan to implement the April 26 Order.

Also on May 25, 2001, the Commission issued its "Order Providing Clarification And Preliminary Guidance On Implementation Of Mitigation And Monitoring Plan For The California Wholesale Electric Markets"[6] wherein the Commission clarified:

- the treatment of generators subject to the must-offer requirement that did not supply adequate heat and emissions data to the ISO;
- calculation of a natural gas proxy price;
- price mitigation in the ISO's spot markets other than the real-time Imbalance Energy market, including the Ancillary Services and Congestion Management markets; and
- creditworthiness requirements with respect to generation dispatched pursuant to the must-offer requirement.

On June 6, 2001, the ISO filed its "Answer of the California Independent System Operator Corporation to Motions to Intervene, Comments, Motion for Leave to File Comments Out of Time, Motion to Reject, and Protests of the May

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[6] 95 FERC ¶ 61,275 ("May 25 Order").

11, 2001 Compliance Filing ("June 6 Answer"), explaining why the May 11 Compliance Filing should be accepted without condition apart from several minor modifications detailed therein.[7]

In its June 19 Order, in explicit recognition that the Western region is "a single market which is at once inextricably interrelated, yet characterized by important differences" the Commission prescribed price mitigation for wholesale spot markets throughout the Western Systems Coordinating Council ("WSCC").[8] In addition to extending the price mitigation scheme to the spot markets in California and the WSCC, the Commission also extended price mitigation to all hours of the day. The Commission's June 19 Order also addresses requests for rehearing of the April 26 Order filed by the ISO and others. Among its other provisions, the June 19 Order:

- reaffirmed 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;

- modified the formula for determining the marginal cost-based "proxy price" for sales in the ISO's spot markets in reserve deficiency hours in California;

- established a single Market Clearing Price in the ISO's spot markets in reserve deficiency hours in California, during which time sellers in the ISO's spot markets will receive a mitigated hourly Market Clearing Price;

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7 The Commission has not yet issued an order on the May 11 Compliance Filing. The ISO's July 10 Compliance Filing is based on, and incorporates, the Tariff revisions submitted in the May 11 Compliance Filing. There is therefore some overlap between the issues parties raised with respect to the July 10 Compliance Filing and those they had previously raised with respect to the May 11 Compliance Filing. As such, the ISO incorporates the discussion provided in its June 6 Answer into the instant answer by reference.

8 June 19 Order at 62,548. References to the WSCC are limited to that portion of the WSCC in the United States and the terms "spot markets" and "spot market sales" are defined to mean sales that are 24 hours or less and that are entered into the day of or day prior to delivery.

- established a maximum Market Clearing Price for spot market sales in all non-reserve deficiency hours that is equal to eighty-five percent (85%) of the highest ISO hourly mitigated Market Clearing Price established during the hours when the last Stage 1 System Emergency was in effect ;

- allowed sellers other than marketers to justify bids or prices higher than the Market Clearing Price, subject to review and refund; and

- restricted marketers from bidding above the Market Clearing Price.

The Commission directed the ISO to submit Tariff revisions necessary to comply with the June 19 Order within fifteen days. On July 5, 2001, the ISO submitted a Motion for Extension of Time to Submit Compliance Filing in this proceeding, requesting that it be permitted an additional three business days to finalize the filing and subsequently, on July 10, submitted its Tariff revisions to comply with the June 19 Order. As directed in the June 19 Order, the July 10 Compliance Filing supplemented the May 11 Compliance Filing. The July 10 Compliance Filing also included modifications that the ISO committed to make in its June 6 Answer and Tariff revisions needed to comply with certain aspects of the Commission's May 25 Order.

On July 19 the ISO filed its "Motion for Clarification and Request for Rehearing" of the June 19 Order ("Request for Rehearing of June 19 Order"). In the Request for Rehearing of June 19 Order, the ISO noted approvingly that the Commission appropriately took a number of much-needed actions to curtail the exercises of market power that have pervaded California wholesale electricity markets for the past year and have driven the price of wholesale electricity in the ISO markets to unjust and unreasonable levels.

Noting that there are several aspects of the June 19 Order that perpetuate the potential for unjust and unreasonable rates and a number of open questions relating to the implementation plan established by the Commission, the ISO specifically requested modification and clarification of the June 19 Order with respect to the following issues:

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

Critically, many of these same issues identified by the ISO are the subject of rehearing and clarification requests made by other parties. Additionally, many of the comments and protests filed by other parties in response to the ISO's July 10 Compliance Filing focus upon these same issues as well. As noted below, to the extent that comments and protests on the July 10 Compliance Filing take issue not with the ISO's implementation of the June 19 Order but instead with the requirements of the June 19 Order itself, such issues should have been raised within the statutory deadline for seeking rehearing of the June 19 Order.

As explained below, the comments and protests of those parties in opposition to the ISO's July 10 Compliance Filing are without merit and should be rejected.

## II. PARTIES FILING INTERVENTIONS, COMMENTS AND PROTESTS

A number of parties have filed motions to intervene, requests for clarification, comments or protests.[9] The ISO does not oppose any of the interventions.

A number of parties filing comments and protests plainly are complaining about the provisions of the June 19 Order itself and not the ISO's implementation of those provisions. For example, the excessive concerns expressed regarding implementation of the must-offer obligation, applicability of mitigated prices levels to various Market Participants and calculation of proxy prices belie a misunderstanding of the Commission's intent. The Commission has determined

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[9] Parties include: AES Southland ("AES"); Allegheny Energy Supply Co., LLC ("Allegheny"); Bonneville Power Administration ("BPA"); California Department of Water Resources ("CDWR"); Cities of Anaheim, Azusa, Banning, Colton and Riverside, California ("Southern Cities"); City of Vernon, California ("Vernon"); Cogeneration Association of California/Energy Producers and Users Association ("CAC/EPUC"); Coral Power, LLC, Enron Power Marketing, Inc., Exelon Corp, Trans Alta Energy Marketing, Inc., Sempra Energy Marketing, Inc., Sempra Energy Trading Corp, BP Energy Co., and Vista Energy ("Coral"); Duke Energy North America, LLC ("Duke"); Dynegy Power Marketing Inc., El Segundo Power LLC, Long Beach Generation LLC, Cabrillo Beach Generation LLC ("Dynegy"); E; Paso Merchant Energy, L.P. ("El Paso"); Independent Energy Producers Association ("IEP"); Metropolitan Water District ("Metropolitan"); Mirant Americas Energy Marketing, LP ("Mirant"); Modesto Irrigation District ("Modesto"); Northern California Power Agency ("NCPA"); Pacific Gas and Electric Company ("PG&E"); Reliant Energy Power Generation, Inc. and Reliant Energy Services, Inc. ("Reliant"); Sacramento Municipal Utility District ("SMUD"); Southern California Edison Company ("Edison"); Sunrise Power Company LLC and Harbor Cogeneration Company ("Sunrise"); Transmission Agency of Northern California ("TANC"); and Williams Energy Marketing and Trading Company ("Williams").

that the provisions in the June 19 Order, and the April 26 Order preceding it, are necessary to address the dysfunctional markets resulting from economic withholding, megawatt laundering and other forms of abusive market power behaviors. The ISO's July 10 Compliance Filing merely implements those measures that the Commission has mandated in order to ensure just and reasonable prices in the California wholesale electricity markets. As the Commission noted, to the extent that Market Participants are dissatisfied with the terms of the June 19 Order, they may engage in forward contracting or apply for cost of service rates to avoid the Order's market mitigation provisions.

Accordingly, to the extent that comments and protests raise substantive concerns about the ISO's implementation of the must-offer obligation, market mitigation plan and other provisions of the June 19 Order the ISO answers such concerns in the following section. To the extent that parties express dissatisfaction with the June 19 Order itself, parties were required to raise such issues within the statutory deadline for requests for rehearing of the June 19 Order. It is inappropriate and contrary to the Commission's regulations for parties to raise or repeat any such issues now in response to the July 10 Compliance Filing. The Commission will act on these issues, if at all, in response to the requests for rehearing of its June 19 Order.

## III. ANSWER TO COMMENTS AND PROTESTS[10]

### A. The ISO Has Properly Implemented the Commission's Mitigation Plan Based on System Emergency Periods.

In the June 19 Order, the Commission held that "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, *i.e.*, Stage 1 when reserves are below 7 percent in California." June 19 Order at 62,548. At footnote 10 in the June 19 Order the Commission stated, "Our April 26 Order referred to Stage 1 being called by the ISO when reserves in California fall below 7.5%. The correct number is 7%." *Id.* at 62,546 n.10. As explained in the ISO's July 10 Compliance Filing, this statement is incorrect. The Commission has indicated its intent to link market mitigation, through proxy prices, to ISO-declared System Emergencies. For example, the Commission specifically references "Stage 1" System Emergencies in providing that the ISO is to establish a maximum Market Clearing Price for non-System Emergency hours equal to "85% of the highest ISO hourly market clearing price established during the hours when the last *Stage 1 (not Stage 2 or Stage 3)* was in effect." *Id.* at 62,548 (emphasis added). Similarly, in the April 26 Order, the Commission

[10] Some of the Intervenors commenting substantively on the ISO's filing do so in portions of their pleadings variously styled as "Requests for Clarification" or "Comments" without differentiation. There is no prohibition on the ISO's responding to the comments in these pleadings. The ISO is entitled to respond to these pleadings and requests notwithstanding the label applied to them. *Florida Power & Light Company*, 67 FERC ¶ 61,315 (1994). In the event that any portion of this answer is deemed an answer to protests, the ISO requests waiver of Rule 213 (18 C.F.R. §385.213) to permit it to make this answer. Good cause for this waiver exists here given the nature of this proceeding and the usefulness of this answer in ensuring the development of a complete record. See, e.g., *Enron Corporation*, 78 FERC ¶ 61, 179 at 61, 733, 61, 741 (1997); *El Paso Electric Company*, 68 FERC ¶ 61, 181 at 61, 899 and n. 57 (1994).

stated that, “The mitigation plan adopted here . . . will establish price mitigation for available capacity in real-time when there is a reserve *deficiency during emergency stages beginning with stage 1*.” April 26 Order, 95 FERC at 61,351 (emphasis added).

As explained in its July 10 Compliance Filing, ISO-declared System Emergencies are not fixed events that automatically occur upon reserves dropping to a specific percentage.[11] System conditions are dynamic, and the ISO continually must forecast both supply and demand, and consider weather trends, day of the week and other parameters in determining the likely conditions that may obtain over an upcoming period of hours. The ISO Tariff expressly provides for the requisite flexibility for the ISO to declare System Emergencies based upon forecasted conditions and to take “immediate manual or automatic action . . . to meet the minimum operating reliability criteria.”[12] Section 2.3.2.1 of the ISO Tariff provides that, “The ISO shall, when it considers that conditions giving rise to a System Emergency exist, declare the existence of such a System emergency. A declaration by the ISO of a System Emergency shall be binding on all Market Participants until the ISO announces that the System Emergency no longer exists.” The necessary alignment of forecasts and a number of conditions means the ISO may not declare a System Emergency every time reserves drop to 7%, because forecasts of relevant parameters may indicate that reserves, while at or just below the 7% level, will increase without ISO

[11] July 10 Compliance Filing at p. 4 n.7.

[12] ISO Tariff Master Definitions Supplement, Appendix A, definition of “System Emergency.”

intervention (for example, if the load is decreasing according to its daily repeatable pattern). Similarly, the ISO could declare a System Emergency when reserves are dropping but have not reached 7% if forecasted parameters suggest that system conditions will not improve otherwise, for example, if load is increasing but no new supplies can be acquired. Flexibility is an essential aspect of managing dynamic systems and as such, the Commission has granted to the ISO such flexibility in declaring System Emergencies.

Thus, based upon the Commission's clear intent to tie proxy price calculation and market mitigation to ISO declaration of System Emergencies, for which the ISO Tariff provides to the ISO operational discretion in declaring, the ISO submitted to the Commission an implementation scheme wherein the trigger to reset the proxy prices is defined by System Emergencies and not an arbitrary reserve percentage alone.[13]

Certain parties argue that the ISO, by invoking its authorized flexibility to manage the Control Area and declare System Emergencies, improperly has acted to garner excessive discretion to itself with respect to the establishment of mitigated Market Clearing Prices in the ISO's markets. These parties appear to fear that the ISO will use such discretion to keep prices unreasonably low.[14] For example, some parties suggest the ISO will refrain from declaring a System Emergency simply to avoid resetting the limitation on Market Clearing Prices during non-emergency hours (the "Non-Emergency Clearing Price Limit"),

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13 June 19 Order at 62,548.

14 These parties include IEP, Duke, Williams, Reliant, Mirant, and NCPA.

presumably to a higher level than such a limitation was previously.[15] These parties argue that the Non-Emergency Clearing Price Limit must be reset whenever operating reserves fall below 7%.

Certain parties' arguments that the Non-Emergency Clearing Price Limit must always be reset when reserves drop below 7% make no sense in light of the fact that this limitation is as likely to be reset at a lower price as at a higher one. External factors including generator availability, weather and the day of week all impact supply and demand, and may combine in unpredictable ways to require an ISO-declared Stage 1 System Emergency. Once a Stage 1 System Emergency is declared, such factors will combine to determine which Generating Unit will be the marginal unit dispatched by the ISO. It is the proxy price of this marginal unit upon which the future Non-Emergency Clearing Price Limit will be based. There is no guarantee that an inflexible trigger to recalculate this limitation whenever system reserves drop below 7% will produce lower or higher prices than would a flexible trigger based upon operating realities. Thus, the argument that the ISO is manipulating declarations of System Emergencies in order to maintain a lower limitation on non-emergency Market Clearing Prices is based on a faulty premise.

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[15] The ISO notes that certain parties argued the precise opposite in their protests of the ISO's May 11 Compliance Filing. Specifically, the parties argued that application of price mitigation during ISO-declared System Emergencies will allow the ISO to abuse its discretion to declare System Emergencies. The Commission had already explicitly considered and rejected such arguments in its April 26 Order, finding "Generators further suggest that the ISO will have an incentive to declare system emergency conditions to invoke mitigated prices, rather than because supply and demand conditions dictate. The WSCC establishes standards for reserve requirements, as well as reporting requirements, and the ISO must observe those standards in declaring emergencies. The Commission also is requiring the ISO to file weekly reports with the Commission, so that the Commission will have information available to review the ISO's actions." April 26 Order, 95 FERC at 61,362.

In addition, the ISO notes that parties' concern with the limitations on non-emergency Market Clearing Prices in the ISO's spot markets belie the whole point of the June 19 Order. These limitations are part of a prescribed cure for the unjust and unreasonable rates in the ISO's spot markets. The June 19 Order's market mitigation plan is intended not only to restore just and reasonable prices the ISO's spot markets but also to encourage greater quantities of generation to be scheduled in forward markets, where they are removed from spot prices and market mitigation measures. Any Market Participant unhappy with the limitations the Commission has established for the ISO's spot markets merely needs to enter into bilateral contracts to realize a mutually negotiated price instead, or as the Commission provides in the June 19 Order, to apply for cost of service rates. For all of the reasons stated above, the ISO has properly implemented the Commission's market mitigation plan in accordance with the ISO's existing standards for declaration of System Emergencies, Stage 1 or otherwise .

### B. The ISO Has Properly Interpreted the June 19 Order's Directive to Use the Hourly Market Clearing Prices When the Last Stage 1 System Emergency Was in Effect for Calculating the Non-Emergency Clearing Price Limit.

Several parties argue that the ISO's method for establishing the clearing price limit for non-reserve deficiency hours is flawed. SCE claims that the ISO should reset the price limit if the price in an hour in which any part of the hour is in a Stage 1 System Emergency if the resulting price limit would be lower than the previous limit. SCE at 2. Dynegy argues that the ISO has abandoned its ten-minute settlement period to establish the clearing price limit to try to produce the lowest possible limit. Dynegy at 5. Williams claims the ISO implemented the

Non-Emergency Clearing Price Limit simply to manipulate the price. Williams at 13.

As explained in substantial detail in the July 10 Compliance Filing,[16] the ISO implemented its best interpretation of the Commission's in order to reconcile the intent of the order and the realities of its software systems as well as to try to ensure a reasonable, equitable outcome that preserves the intended market power mitigation aspects while avoiding skewing prices unnecessarily. While parties argued that the ISO should set the clearing price based on a ten minute interval, the June 19 Order clearly directed the ISO to establish the Non-Emergency Clearing Price Limit using "the highest ISO *hourly* market clearing price established during the hours when the last Stage 1 was in effect." June 19 Order at 62,548 (emphasis added). Implementing the Commission's order does not constitute abandoning the ISO's ten minute settlement paradigm.

Generators' umbrage at the ISO's ten minute settlements paradigm is hardly surprising, given that the ISO implemented this system to curb the potential for gaming of an hourly market. Furthermore, the fact that the Non-Emergency Clearing Price Limit has remained stuck at its original implementation level does not mean the ISO's implementation of this limit was unreasonable.[17] Given the dire forecasts for frequent rolling blackouts in California in the summer of 2001, no party could have anticipated the factors, such as the dramatically successful conservation efforts by the citizens of California, that have led the ISO

[16] July 10 Compliance Filing at 13-15

[17] The ISO provided a detailed rationale for its implementation of the Non-Emergency Clearing Price Limit in its July 10 Compliance Filing at 13-15.

to declare System Emergencies only on two days since the implementation of the June 19 Order.[18] Even given only two days with declared System Emergencies since the June 19 Order was implemented, the fact that the Non-Emergency Clearing Price Limit has not changed is still anomalous, since a survey by the Department of Market Analysis of previous System Emergencies indicated that in 94% percent of the previous System Emergencies, a Stage 1 System Emergency existed for at least an hour. In sum, while the unforeseen result of a stuck Non-Emergency Clearing Price Limit is unexpected, and not what could have been reasonably expected, it does not mean that implementation was erroneous. Moreover, as described above, any declaration of a full hour of a Stage 1 System Emergency could just as easily lower as well as raise the Non Emergency Clearing Price Limit.

### C. The July 10 Compliance Filing Properly Requires Bid Justification For All Bits Submitted Above the Applicable Market Clearing Price Limitations.

A number of parties argue that the ISO should not require bid justification for all bids in its real-time markets above the proxy price of the unit (during System Emergencies) or the Non-Emergency Clearing Price Limit (during non-emergency periods) unless such bids are accepted by the ISO. Some parties request that proposed revisions to Tariff Section 2.5.23.3.5, filed in the July 10 Compliance Filing, be rejected or amended to remove the corresponding requirement that all bids above the proxy price or the Non-Emergency Clearing

[18] July 2 and 3, 2001.

Price Limit must be cost justified whether accepted or not.[19] Similar comments were filed in response to the ISO's May 11 Compliance Filing and the ISO responded to these comments in its June 6 Answer at 51.

The obligation to submit cost justification is incurred when a generator submits a bid above the proxy price or the Non-Emergency Clearing Price Limit (as applicable), and is not contingent upon the ISO's acceptance of such a bid. Were generators free to submit any bids at all with no supporting data to document the reasonableness of such bids, generators would be free to engage in abusive bidding practices which would effectively gut the provisions of the must-offer obligation and market mitigation plan. Unreasonably high bids, even if not accepted by the ISO, can serve to withhold generation just as effectively as can a failure to bid at all. The end result is the same: available capacity and energy is withheld from ISO real-time markets whenever generators are dissatisfied with the prices or otherwise wish to engage in strategic withholding.[20] This is a core problem that both the April 26 and June 19 Orders seek to remedy by requiring bid justification. Only by close examination of bidding practices can the ISO and the Commission monitor compliance with the prohibition on anti-competitive bidding.

[19] Parties include: Allegheny at 2; IEO at 11; Mirant at 13-14; Dynegy at 16; Duke at 21, 26; and Williams at 15.

[20] The ISO notes that generators can also engage in strategic withholding by declining ISO Dispatch instructions for bids offered to the ISO – a practice which has sharply increased in recent months.

### D. The ISO Tariff Already Provides That the Only Penalty For Having a Unit Forced Out-of-Service Is the Cost of Replacement Energy.

Despite the fact that the ISO has certain sanction and penalty authority under the Tariff and did not propose to reduce or expand such authority in either of its compliance filings for the April 26 and June 19 Orders, some parties continue to object to existing Tariff provisions relating to the ISO's sanction and penalty authority and argue that the ISO should have modified those Tariff provisions to comply with the Commission's directive in the June 19 Order that "the only penalty for having a unit forced out of service is the cost of replacement energy."[21] June 19 Order at 62,553. As noted in the ISO's July 10 Compliance Filing at 10-12, the ISO believes that the Commission may harbor a misunderstanding of ISO Tariff presently governing Forced Outages and the application of penalties to a generating unit that goes offline due to a Forced Outage. Section 5.6.3 of the ISO Tariff does provide for a penalty equal to twice the highest price paid for energy in the relevant hour during a System Emergency in which a Scheduling Coordinator fails to comply with a Dispatch Instruction. However, Section 5.6.3.2 of the ISO Tariff provides that all a Scheduling Coordinator or Participating Generator must do to avoid the penalty is *notify the ISO within one hour that the generating unit was/is physically incapable of responding to the Dispatch Instruction.* A simple telephone call avoids the penalty. A telephone call to the ISO permits the ISO to undertake appropriate

[21] The objecting parties include: BPA at 1; Mirant at 6; Dynegy at 17; Williams at 8; and Reliant at 12-13.

alternative actions to compensate for the capacity or energy that any such Generating Unit cannot provide because it is on a Forced Outage. As the ISO noted in its July 10 Compliance Filing, timely notification of a change in a generating unit's status is imperative if the ISO is to reliably operate the system and is consistent with the Commission's previous directives regarding the need for enhanced Outage coordination. Nothing in the June 19 Order addresses Section 5.6.3. The Commission has never found this to be an unreasonable Tariff requirement and has never ordered the ISO to modify it.

As further noted in its July 10 Compliance Filing at 11, with respect to scheduled energy and charges incurred for over-scheduling generation, the ISO Tariff is consistent with the Commission's directions that the "only penalty for having a unit forced out of service is the cost of replacement energy." Where a Scheduling Coordinator fails to provide scheduled energy due to a Forced Outage or other reasons, it is assessed the cost of the energy needed to replace that which was not delivered as scheduled. In such a case, the cost of replacement energy is *not* a penalty: it is the cost of energy that ISO must procure to maintain Load and generation balance in real-time and the cost of additional Replacement Reserve the ISO must purchase to ensure unscheduled deviations do not cause the ISO to violate reliability criteria. Therefore, assessing the cost of replacement energy against Scheduling Coordinators that fail to deliver scheduled energy is wholly consistent with cost-causation principles and not a penalty at all.

As noted above, however, the ISO Tariff provides for a penalty of twice the cost of replacement energy *if Instructed Energy is not delivered during a System Emergency AND a Forced Outage is not reported within the hour to the ISO.* This penalty requires that a System Emergency be in effect, and not only the failure of a generator to comply with Dispatch instructions but also a failure to provide the ISO with essential and timely notice of the generator's change in status during emergency conditions. Given that timely notification of a change in a generating unit's status is essential to reliable operation of the ISO's Control Area, the ISO believes that the present outage reporting requirements, costs for replacement of energy scheduled but not delivered and penalties that apply only for failing to report outages and failing to comply with Dispatch Instructions during a System Emergency are consistent with the Commission's directives on this issue in the June 19 Order. In sum, the ISO Tariff presently implements the Commission's specific intent and does not require revision in this regard.

### E. The ISO's Tariff Revisions of the Must-Offer Obligation Are Consistent With the April 26 and June 19 Orders.

A critical, and contentious, feature of the Commission's market mitigation plan, as established in the April 26 Order and modified in the June 19 Order, is the must-offer obligation. The April 26 Order mandated that all sellers that own or control non-hydroelectric generators located in California that make sales through the ISO's markets or that use the ISO Controlled Grid, including non-public utility sellers, offer the ISO all of their capacity in real-time during all hours if it is available and not already scheduled to run through bilateral agreements. April 26 Order at 61,355-57. While the June 19 Order clarified the must-offer obligation with regards to municipal utilities (that the must-offer obligation applied only to power left over after the municipal's own needs are satisfied) and Qualifying Facilities ("QF") (that the QF is subject to must-offer obligation if it chooses not to sell its maximum output to the utility with whom it has an agreement), it clearly and expressly affirmed the must-offer obligation as previously set forth in the April 26 Order. The Commission imposed this obligation to ensure that the ISO will be able to call upon available resources in the real-time market to the extent that energy is needed. As the Commission realized, price mitigation without the must-offer obligation is useless, since sellers can otherwise simply refuse to sell power if they don't like a mitigated price.

Some parties assert that the ISO went beyond the Commission's intent in implementing the must-offer obligation. As the ISO explains below, these objections are without merit. The Tariff provisions related to the must-offer obligation submitted in the July 10 Compliance Filing are consistent with and necessary to implement the April 26 and June 19 Orders. To the extent parties object to the scope of those provisions, their objections are to the Commission's orders themselves

Several parties protest the applicability of the must-offer obligation to units with long start-up times. For example, Sunrise contends that, by requiring units with long-start up times to be available to provide energy from their available capacity in real-time, the ISO's Tariff revisions implementing the must-offer requirement have converted the obligation established by the Commission into a "must-run" obligation well beyond the Commission's intent. Sunrise at 5. The

Commission's must-offer obligation, however, requires generators to offer all of their available capacity *in real-time*. As Sunrise points out, the ability of a generator to make its capacity available in real-time depends on the generator's operating characteristics. Sunrise at 7. AES similarly notes that what is "available" depends on the unit's operating characteristics. The ISO agrees that generating units have different operating characteristics that affect how much capacity can be made available in real-time. The ISO has generally interpreted this requirement so that units that start-up and increase load in an hour or less comply with the obligation to make their capacity available in real-time even when they are off-line. This interpretation would also hold, for example, for the diesel units owned by the City of Vernon, which can come on-line in a relatively short time and therefore are not required, as Vernon seeks to be clarified, to operate continuously to satisfy the must-offer obligation. Vernon at 5. The ISO does not intend that such units operate at all times.

Nothing in the June 19 or April 26 Orders suggests that units with long start-up times should be exempted from the must-offer requirement or afforded special treatment in the implementation of that requirement. Indeed, implementation of the must-offer obligation in a manner that exempts units with long start-up times would be inconsistent with the Commission's finding in the June 19 Order that, "Given the shortage of power in California, all generators in California, including municipals, should not hold energy in reserve (over minimum acceptable levels) when the energy is needed to meet demand." June 19 Order at 62,553. As the ISO explained in the July 10 Compliance Filing, permitting generators to declare units with long start-up times as "unavailable" to the ISO real-time market when they are physically capable of operating completely undermines the must-offer obligation.

Nonetheless, the ISO has acknowledged that not every long start-up unit is required to be on-line at all times for the ISO to ensure system reliability and competitive markets.[22] Consequently, in keeping with its pledge to work with other parties to implement a solution to this problem,[23] the ISO implemented a practice in which it notifies units with long start-up times that it does not intend to call upon such units when supplies and system conditions permit. In this practice, generators that wish to shut down notify the ISO of their desire to shut down after the close of the Day-Ahead scheduling process. After evaluating system conditions to ensure that sufficient generation and imports remain available in real-time to: 1) serve load and provide reserve margins with a reasonable margin of forecast error; 2) facilitate a competitive market; and 3) take care of any local reliability concerns, the ISO determines which units may be shut down and notifies, in the order in which the requests were received, those units not needed that they will not be dispatched by the ISO until otherwise notified by the ISO that they are needed, allowing these units to shut down without fear that the ISO will identify them as not complying with the must-offer requirement.[24] The ISO holds that this practice of allowing units to shut down

[22] July 10 Compliance Filing at 8.

[23] *Id.*

[24] This practice is described in the Market Notice provided as Attachment A to this answer. For ease of understanding, this practice is described as a “waiver” from the must-offer requirement although, in practice, it is a waiver of the ISO’s must-offer compliance verification procedures for the applicable unit.

with ISO permission (and deeming units so permitted to still be in compliance with the must-offer obligation) is more favorable than a strict interpretation of the must-offer obligation that arguably would require these long start-up time units to remain on-line regardless of system conditions. This practice is not intended to modify the obligations of generators under the Commission's orders and, when conditions warrant, the ISO may revoke its notification that a unit will not be needed under the must-offer obligation. In that circumstance, the unit must then return on-line to comply with the must-offer obligation.

The IEP asserts that the ISO's requirement that long start-up units deemed necessary to serve load remain on-line allows for the ISO to take operating reserve without compensation. IEP at 5-6. This claim is false. With a very limited and necessary exception, the ISO procures its operating reserves only through its markets.[25] Units that are operating at minimum Load in order to comply with the must-offer obligation are not taken into account in the ISO's calculation of operating reserve. The ISO does, however, encourage such generators to bid into the Ancillary Services markets so they are compensated for maintaining available capacity. If such capacity is bid and accepted into the ISO's markets, it will no longer be considered "available capacity" subject to the must-offer requirement. Indeed, the ISO does not understand why the IEP or other parties would not take advantage of this opportunity to earn compensation for their available capacity.

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[25] The ISO can call on Reliability Must-Run Units to provide Ancillary Services only in the event the market does not provide sufficient Ancillary Services.

Several generators object to the requirement that units with long start-up times remain on-line to comply with the must-offer requirement with no guarantee of recovering their costs of staying on-line. In its protest, Williams details the losses that a "particular unit" would incur if that unit had to remain on-line at minimum load for five days to comply with must-offer obligation. Williams acknowledges that this "particular unit" was then off-line, along with three other units, based on the ISO's notification that the unit would not be needed for ISO Dispatch. Williams at 3-4. Once again, the ISO notes that these objections relate not to the ISO's implementation of the must-offer obligation, but to the obligation itself. Williams and others point to nothing in the June 19 Order which provides that such long start-up units are entitled to additional compensation for minimum load costs incurred to comply with the must-offer obligation even when they are not providing services to Load in California.

Sunrise claims that a day-ahead scheduling procedure under which the ISO would ensure the recovery of the costs of operating at minimum load would address the concerns of such long start-up units. Sunrise at 9. While the ISO agrees that a day-ahead scheduling process has some promise, and should be explored, the ISO holds that the solution to this problem is not simply to guarantee recovery of minimum load costs. Such a solution would provide generators with the best of both worlds – an opportunity to earn revenues above their costs through market-based rates when prices are favorable and a simultaneous guarantee to cover all their costs when prices are not favorable[26]. The ISO also holds that the solution to this problem is not simply to allow the generators the discretion to determine when they are or are not available to comply with the must-offer obligation. That solution completely recreates the problem of physical withholding that the must-offer obligation is designed to eliminate. In addition to the Ancillary Service option described above, the generators already hold one possible solution in their own hands. That solution is one the Commission intends to encourage – forward contracting. Sellers can negotiate a price that covers the high average costs of operating near minimum load and covers other costs such as start-up costs and no-load costs that the Commission clearly intends to remain out of the ISO's energy Market Clearing Price. Having these costs assigned to a particular buyer would also keep them from being allocated to all Market Participants through the ISO's uplift charge. These costs should not be recovered primarily, let alone solely, through the ISO markets, which the Commission clearly intends to be a small portion of overall electricity market volume. As the Commission stated in the June 19 Order, "under the FPA and our authorization for market-based rates, sellers are not guaranteed to recover all costs but are provided the opportunity to do so." June 19 Order at 62,564. The availability of the bilateral contract and Ancillary Service options confirms that even long start-up units subject to the must-offer requirement retain this opportunity.

[26] As the Commission noted in the June 19 Order, cost-based rates are available to generators who find market risk too distasteful. June 19 Order at 62,564.

### F. The June 19 Order Approved the Use of Incremental Heat Rates in Calculating Proxy Prices.

Reliant and Duke argue that the ISO should determine the "proxy price" used to mitigate Market Clearing Prices during non-System Emergency periods based on average heat rate rather than on incremental heat rate. Reliant at 15. Duke at 6-7. These arguments should be rejected. The Commission specifically approved the ISO's methodology of using incremental heat rates in the June 19 Order:

> As noted by the ISO, 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. The ISO's proposal to include the minimum and maximum operating levels for each unit and nine points in between is reasonable.

June 19 Order at 62,563.[27]

Even if the June 19 Order did not provide such specific direction, the use of average heat rates would produce severely distorted prices. The April 26 Order required that the heat rates submitted by generators to be used to determine the proxy price "must reflect operational heat rates that do not include start-up and minimum load fuel costs because, in a declared emergency, the market clearing price should reflect the cost to generate at or near maximum outputs." April 26 Order at 61,359. There is no guarantee, however, even in System Emergencies, that the marginal unit setting the Market Clearing Price will

[27] The ISO notes that the June 19 Order is incorrect in subsequently stating that "the ISO's heat rate curve reflects the minimum fuel load requirements requested by Williams." *Id.* The ISO's incremental heat rate curves do not reflect the minimum fuel load requirements. For reasons discussed below, this is consistent with the Commission's directives in the April 26 Order.

be operating at or near maximum load, especially if the unit is not fully loaded because it is providing Ancillary Services. The average heat rate of units that are not operating at or near full load can be quite high, even higher than the cost of a unit dispatched at or near its full output to meet increasing load. Moreover, since generators will reasonably seek to maximize profits by providing energy from lower cost units first, it is likely that the units providing Ancillary Services will be the more inefficient units with high average heat rates, especially when operating below full load. The ISO does not believe that the Commission could have intended that these partially loaded units would set a Market Clearing Price. Consequently, the ISO used incremental heat rate curves – which reflect the cost of producing an additional MW of output – in calculating the proxy price, and this approach was approved in the June 19 Order.[28]

### G. The ISO Has Implemented the Ancillary Service Price Mitigation In Accordance With the May 25 and June 19 Orders.

In the July 10 Compliance filing, as modified by the ISO's July 30, 2001, errata filing in this proceeding, the ISO filed Tariff revisions to implement the Ancillary Service price mitigation scheme established by the Commission's May 25 Order and affirmed in the June 19 Order.[29] Reliant argues that the price mitigation in day-ahead and hour-ahead Ancillary Services markets should be set at the time the transactions are entered into, and that mitigation remain in place during the delivery hour. Reliant at 21-23. Reliant argues that the prices in the

[28] May 11 Compliance Filing at 7.

[29] The July 30 filing replaced the improper usage of the term "Marginal Proxy Clearing Price" in the Ancillary Service price mitigation Tariff provisions with the more accurate term "Hourly Ex Post Price."

forward markets should not change retroactively based on what mitigation may have occurred in real-time. Reliant's concerns, however, are not with the details of the ISO's implementation of Ancillary Service price mitigation, but rather with the requirements of the Commission's May 25 Order in this proceeding. In that order, the Commission held that:

> With respect to calculating the market clearing price for Ancillary Services, we direct the ISO to use each relevant average hourly mitigated Imbalance Energy price. If the Ancillary Services markets clear below the average hourly mitigated Imbalance Energy price for that hour, then the ISO will pay the Ancillary Services clearing price for that market. If the Ancillary Services markets clear above the average hourly mitigated Imbalance Energy price, then the ISO will use that price to clear the market and will pay as-bid for all Ancillary Services that are needed above the mitigated price. Bids accepted above the mitigated price will be subject to refund and justification.

May 25 Order at 61,971-72. This mitigation methodology was affirmed in the June 19 Order. This language makes it clear that the Commission intended an *ex post* mitigation of Ancillary Service prices based on "the average hourly mitigated Imbalance Energy price for [the applicable] hour." Accordingly, the approach Reliant argues for is not consistent with the Commission's orders in this proceeding.

### H. The ISO's Determination of Entities Eligible To Set the Market Clearing Price Is Necessary For the ISO To Implement The June 19 Order's Designation of Marketers as "Price Takers."

Many parties raise concerns about aspects of the July 10 Compliance Filing addressing the treatment of marketers, the determination of which entities will be eligible to set Market Clearing Prices, and the ISO's proposal that only those suppliers that have signed a Participating Generator Agreement ("PGA") may set the Market Clearing Price and to seek to justify prices above the mitigated Market Clearing Price. As explained below, and in greater detail in the ISO's July 10 Compliance Filing,[30] the operational realities of the ISO's interaction with and "visibility" of suppliers in its markets requires such an approach if the ISO is to fully implement and monitor compliance with the mitigation plan established in the June 19 Order.

The June 19 Order establishes a number of restrictions concerning the bids marketers can submit to the ISO's markets and the prices they can earn in those markets. The Commission held that "marketers will be required to be price takers. This means that marketers cannot bid higher than the market clearing price." June 19 Order at 62,548. The Commission further stated that "all marketers in the ISO's markets must now be price takers and cannot justify a bid higher than the mitigated price." *Id.* at 62,554; *see also Id.* at 62,565. These restrictions were established by the Commission to address the ability of suppliers to circumvent price mitigation mechanisms through "megawatt laundering." As noted in the July 10 Compliance Filing, the ISO commends the Commission for addressing the megawatt laundering problem.

A number of parties contend that, under the June 19 Order, marketers should be permitted to set the Market Clearing Price either during non-Emergency hours or during all hours. *See, e.g.*, Coral at 5-8; Mirant at 9-10; Dynegy at 7-8. These parties do not provide any convincing or colorable rationale as to how such an approach can be consistent with an order mandating

[30] July 10 Compliance Filing at 15-17.

that marketers: 1) be “price takers”; 2) be prohibited from bidding above the Market Clearing Price; and 3) be prohibited from seeking to justify prices above the mitigated Market Clearing Price. In essence, the objections of these parties are to the June 19 Order itself and not the ISO’s implementation of that order with respect to marketers. Such objections therefore must be addressed in the context of a request for rehearing of the June 19 Order. These objections do not address the ISO’s compliance with the June 19 Order.

The Commission’s June 19 Order pre-supposes a distinction between "marketers" and "other sellers" (*i.e.*, non-marketer importers of energy into California and resources within California) that may set the Market Clearing Price and may seek to justify prices above the mitigated Market Clearing Price. As a practical matter, however, the energy bid by a “marketer” looks the same as any other energy bid into the ISO Markets or scheduled on the ISO Controlled Grid, if such energy is not associated with a specific resource. If the ISO does not have operational data and operational "visibility” (*i.e.*, telemetry) on the generating units of "other sellers" (*i.e.*, importers and other non-public utility generators in California), the ISO cannot distinguish such sellers from marketers. Moreover, absent such visibility, the ISO, and ultimately the Commission, will be unable to verify such resources’ compliance with Commission’s must-offer obligation and other requirements of the June 19 Order.

In the July 10 Compliance Filing, the ISO explained that, in order to allow the ISO to distinguish such “other sellers” from marketers, the generating units of these other sellers should be visible to the ISO’s monitoring systems as separate resources and should meet the ISO's scheduling and metering standards. Such standards are consistent with the standards required of Participating Generators. It is for this reason that the ISO proposed, in the July 10 Compliance Filing, to limit the entities eligible to set the Market Clearing Price and to seek to justify prices above the mitigated Market Clearing Price to those non-marketer suppliers that have signed a Participating Generator Agreement and therefore satisfy those scheduling and metering standards. Nothing in any of the comments or protests addressing this proposal has altered the operational realities which led the ISO to conclude that it must adopt such an approach.

### I. The ISO's Proposed Recovery Mechanism for Emissions Costs and Start-Up Fuel Costs Is Consistent With the June 19 Order and Commission Precedent.

The June 19 Order directed the ISO "to develop a specific emission allowance administrative charge assessed against all in-state load served on the ISO's transmission system" which will permit generators to invoice the ISO "in order to recover NOx emission mitigation costs assessed against generators that are required to run in accordance with ISO Dispatch instructions and the must offer provisions of this order." June 19 Order at 62,562. The Order further provides that generators may "invoice the ISO their actual start-up fuel costs for recovery by the ISO in the same manner that emissions costs are recovered." *Id.* at 62,563.

In the July 10 Compliance Filing, the ISO proposed Tariff revisions to implement two separate charges (the "Emission Cost Charge" and the "Start-Up Fuel Cost Charge") to be assessed against Scheduling Coordinators based on their Demand within the ISO Control Area and their Demand within California but outside the ISO Control Area which is served by exports from the ISO Control Area. Because the ISO is unable to predict in advance the NOx emission costs and start-up fuel costs that will be invoiced to it, and because these costs are likely to vary considerably over time, the ISO proposed a formula rate structure for these charges whereby the rate for these charges can be adjusted over time based on defined parameters and with advance notice to Market Participants.

A number of parties raise concerns with the ISO's proposed mechanism for assessing these charges against Market Participants. The ISO notes that many of these concerns are with the June 19 Order itself and not necessarily the ISO's implementation of that Order. For example, PG&E contends that these charges should be assessed on out-of-state exports (PG&E at 3), despite the Commission's directive that these charges be assessed against "all in-state load served on the ISO's transmission system." Similarly, Metropolitan's argument that these charges should be assessed only against Load during peak periods is contrary to the Commission's directive that the charges be assessed against "*all* in-state load" because "all customers within California benefit from cleaner air as a result of application of these mitigation fees." June 19 Order at 62,562 (emphasis added).

CDWR raises similar issues about the allocation of these charges, but also takes issue with the fact that these charges are proposed in the form of formula rates. CDWR suggests that because these charges may be periodically adjusted, without a formal FERC filing, such charges "will be assessed without compliance with Federal Power Act rate-making requirements. CDWR at 3. CDWR apparently fails to acknowledge that formula rates are consistent with the Federal Power Act.[31] In fact, the formula rate structure proposed for the Emission Cost Charge and the Start-Up Fuel Cost Charge is closely modeled on a formula rate structure previously proposed by the ISO and accepted by the Commission. In its order on Amendment No. 35 to the ISO Tariff, the Commission accepted ISO Tariff Section 7.5 concerning the ISO's pass-through of FERC Annual Charges. *California Independent System Operator Corp.*, 94 FERC ¶ 61,266 (2001). Section 7.5.3.2 allows for periodic adjustments of the FERC Annual Charge Recovery Rate, based upon a number of variables, with the adjusted rate to be posted on the ISO Home Page, but not filed with the Commission. The proposed provisions for adjustment of the Emission Cost Charge and the Start-Up Fuel Cost Charge require a similar process.

As CDWR notes, the ISO issued a Market Notice concerning the initial rates of the Emission Cost Charge and the Start-Up Fuel Cost Charge on August 1, 2001.[32] CDWR objects to the retroactive nature of these initial rates. CDWR at 3-4. Again, CDWR fails to recognize that a retroactive application was mandated by the Commission, which explicitly granted a waiver of notice for these rate mechanisms. June 19 Order at 62,548 n.14. All future adjustments to

[31] When the Commission accepts a formula rate as a filed rate, it grants waiver of the filing and notice requirements of section 205 of the Federal Power Act . . . [The utility's] rates, then, can change repeatedly, without notice to the Commission, *provided* those changes are consistent with the formula." *San Diego Gas & Electric Co. v. Alamito Co.,* 46 FERC ¶ 61,363 at 62,129-30 (1989) (emphasis in original).

[32] A copy of this Market Notice is provided as Attachment B.

the Emission Cost Charge and the Start-Up Fuel Cost Charge will be prospective, with advance notice posted on the ISO Home Page.

Vernon objects to the provisions of proposed Sections 2.5.23.3.6.7 and 2.5.23.3.7.7 that provide for adjustment of these charges if there are insufficient funds available to pay submitted invoices. Vernon at 8. Vernon's concerns are misplaced. Under proposed Sections 2.5.23.3.6.4 and 2.5.23.3.7.4 non-payment of Emission Cost Charges or Start-Up Fuel Cost Charges is not one of the variables to be taken into account in adjusting the rate for these charges. As such, these provisions are not analogous to the California Power Exchange's "charge-back" mechanism as Vernon seems to fear. These sections do, however, permit for adjustment of these charges if the actual NOx emission costs and/or start-up fuel costs that are the direct result of an ISO Dispatch instruction are significantly more or less than the ISO's projections.

PG&E requests clarification as to whether the ISO will assess the Emission Cost Charge and the Start-Up Fuel Cost Charge on a "gross" or a "net" basis. PG&E at 3. Consistent with the Commission's directive that these charge be "assessed against all in-state load served on the ISO's transmission system," the ISO believes it is most appropriate to assess these charges to all ISO Control Area Gross Load within the ISO's Control Area and to all Load exported from the ISO Control Area to another Control Area in California. "ISO Control Area Gross Load" includes all Demand for Energy within the ISO Control Area. The ISO recognizes that such an allocation may not be clear from the specific Tariff language proposed in the July 10 Compliance Filing ("metered Demand within the ISO Control Area and their Demand within California but outside the ISO Control Area which is served by exports from the ISO Control Area"). Accordingly, the ISO commits to modify this Tariff language in a subsequent compliance filing unless the Commission does not accept the ISO's interpretation of the appropriate allocation for these charges.

AES argues that the Emission Cost Tariff provisions should be modified to require the Scheduling Coordinator that represents a given generator to submit that generator's NOx costs and to require the Scheduling Coordinator to remit any reimbursements for such costs to the applicable generator. AES at 4. Such a modification is both unnecessary and inappropriate. As the Commission has recognized on numerous occasions, Scheduling Coordinators are the appropriate representatives of entities that participate in the ISO's markets and/or that schedule energy over the ISO Controlled Grid. The ISO Tariff does not address the relationship between those Scheduling Coordinators and the entities that they represent. To the extent that any generator has concerns about the behavior of its designated Scheduling Coordinator, that issue must be resolved between those two parties. It cannot be resolved through the ISO Tariff.

### J. Only Units Dispatched By the ISO Are Eligible To Recover Emission Costs or Start-Up Fuel Costs From the ISO.

Several parties take issue with the requirement that Emission Costs or Start-Up Fuel Costs be shown to be the direct result of an ISO Dispatch instruction in order for such costs to be invoiced to the ISO. *See, e.g.*, Duke at 20-21. These parties argue that generators should be entitled to recover *all* of their Emissions Cost and Start-Up Fuel Costs, regardless of whether they have been dispatched by the ISO or not. Specifically, they argue that the ISO should compensate them for such costs incurred as a result of spot bilateral transactions in California (*i.e.*, those bilateral transactions that are 24 hours or less and that are entered into the day of or the day prior to delivery). Duke at 21.

These arguments are inconsistent with the Commission's directive in the June 19 Order that the ISO create a mechanism that will permit recovery of "NOx emission mitigation costs [and start-up fuel costs] assessed against generators that are required to run in accordance with ISO Dispatch instructions and the must offer provisions of this order." June 19 Order at 62,562. Such a limitation makes perfect sense. The must-offer obligation is a mandatory requirement to offer available capacity into the ISO's real-time market. Thus, it is only those generators that have been required to offer energy in the ISO's market *and that have been dispatched by the ISO* that are being compelled to operate without an opportunity to recover their NOx emissions costs or start-up fuel costs.

While it is true that spot market bilateral transactions are subject to price mitigation under the June 19 Order, no generator is under an obligation to enter into such bilateral spot market transactions. If a generator is unable to recover its costs through such a bilateral transaction, it simply should not enter into such a bilateral arrangement. If such a generator has available generation in real-time, it will then be required to offer that generation in the ISO's real-time market, but it will also then have the opportunity to recover NOx emissions costs and/or start-up fuel costs if dispatched by the ISO. The July 10 Compliance Filing therefore appropriately implements the June 19 Order by providing for the ISO payment of such costs to only those generators that are subject to the must-offer requirement and that are required to run in accordance with ISO Dispatch instructions.

### K. The Ten Percent Credit Risk Adder Is Properly Limited To the Market Clearing Price Paid To Generators For Prospective Sales in the ISO Markets.

The June 19 Order requires the ISO "to add 10 percent to the market clearing price paid to generators for all prospective sales in its markets to reflect credit uncertainty." June 19 Order at 62,548 n.13 and 62,564. A few parties raise concerns about the Tariff revisions implementing this requirement. Duke contends that the ISO should clarify what sales do and do not qualify for this credit adder. Duke at 18-19. The ISO clarifies that, consistent with the Commission's directives, it has assessed the ten percent credit adder on the charges and payments for all sales in the ISO Markets at the Market Clearing Price for those markets. The ISO determines a Market Clearing Price for capacity sold in its Ancillary Service markets and for energy sold in its Imbalance Energy market. To the extent that Duke contends that the ten percent credit adder should also be added to sales in those markets above the applicable Market Clearing Price (Duke at 20), such an application is inconsistent with the plain language of the June 19 Order, which explicitly ties the ten percent adder to "the market clearing price paid to generators."

Dynegy contends that the ten percent credit adder should be applicable to Congestion revenues which result from both incremental and decremental Adjustment Bids. Dynegy at 15. Such an application is also inconsistent with the

June 19 Order. Congestion revenues (*i.e.,* Usage Charges) are not the results of sales into the ISO's markets.[33] Instead, this is the mechanism by which Scheduling Coordinators can prioritize, and pay for, use of a congested interface on the ISO Controlled Grid. In addition, there are no Market Clearing Prices generated by the ISO's Congestion Management system. Therefore, Congestion revenues cannot fall within the scope of "the market clearing price paid to generators for . . . prospective sales in [the ISO's] markets."

Mirant claims that the ten percent credit adder should not be assessed against generators because they are creditworthy entities. Mirant at 16-17. Specifically, Mirant contends that the ten percent adder should not be applicable to charges to generators for "Net Negative Uninstructed Deviations." There is nothing in the June 19 Order which would suggest or even permit such an exemption. Although the ten percent adder is intended to address credit risk in the ISO's markets, the Commission clearly stated that the adder is to apply to "all prospective sales in [the ISO's] markets" and not just sales on behalf of entities that are not creditworthy.[34]

Not only is the exemption proposed by Mirant inconsistent with the June 19 Order, such an exemption would lead to illogical results. Under Mirant's approach, the ISO would not impose the ten percent adder to the charges assessed against generators that fail to deliver scheduled energy (*i.e.*, that are

[33] Notably, the definition of "ISO Markets" in the ISO Tariff does not include any reference to Congestion Management.

[34] The ISO also notes that Mirant's claim that generators are the "only fully creditworthy parties in the California market" is demonstrably false. Numerous participants in the California wholesale markets, such as the municipal utilities and many others, remain fully creditworthy.

responsible for Negative Uninstructed Deviations). As Mirant acknowledges however, "in effect, the generator [that is charged for the Net Negative Uninstructed Deviation] is purchasing power from the ISO in real time to make up for the energy the generator has failed to deliver." Mirant at 16. That power is not truly purchased from the ISO but rather through the ISO's real-time Imbalance Energy market from some other supplier *that will expect to be paid the ten percent credit adder.* That supplier cannot be paid the adder unless the party charged for that energy, in this case the deviating generator, also pays the adder. In order to maintain the symmetry of payments and charges in the ISO's markets, and to ensure that the ISO can continue to operate as a revenue-neutral not-for-profit entity, the ten percent adder must be applicable not only to payments for Imbalance Energy but also to all charges for Net Negative Uninstructed Deviations.

## IV. CONCLUSION

For the foregoing reasons, the Commission should accept the ISO's July 10 Compliance Filing in this proceeding without substantive modification.

Respectfully submitted,


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Dated: August 24, 2001

## CERTIFICATE OF SERVICE

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

Dated at Washington, DC, this 24th day of August, 2001.

Sean A. Atkins
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