UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company Complainant, v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange, Respondent,	)	Docket No. EL00-95-001
California Independent System Operator Corporation	)	Docket No. ER02-1656-000

MOTION FOR LEAVE TO FILE ANSWER AND ANSWER OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION TO PROTESTS

Pursuant to Rules 212 and 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. § § 385.212 and 385.213, the California Independent System Operator Corporation ("ISO") hereby requests leave to file an answer, and files its answer, to the protests and comments filed by certain intervenors in the captioned proceeding.

In support hereof, the ISO respectfully states as follows:

I.

MOTION FOR LEAVE TO FILE ANSWER

Rule 213(a)(2) of the Commission's Rules of Practice and Procedure provides that answers to protests generally are not allowed "unless otherwise ordered by the decisional authority." However, in the past the Commission has allowed the filing of answers to protests for various reasons demonstrating good cause.[1]

The ISO submits that good cause exists to grant the ISO leave to respond to the various protests filed in this proceeding. The ISO's Answer will lead to a more accurate and complete record and will assist the Commission in understanding the issues in this proceeding and reaching a decision. For these reasons, the ISO respectfully requests that the Commission accept the following Answer.

II.

ANSWER

A. Procedural Background

On May 1, 2002, the ISO filed its Comprehensive Market Design proposal ("MD02 Filing") with the Commission. The market design changes proposed in the MD02 Filing address deficiencies in the ISO's existing market design and will enable the ISO to perform its core function-- providing open access, reliable and non-discriminatory transmission service-- more effectively. In particular, the proposed market design changes will promote the development of more stable markets by fostering forward markets for energy, facilitating development of a capacity requirement for operating a reliable grid, eliminating the balanced schedule requirement, allowing multi-part bids and accommodating demand

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[1] The Commission has held that good cause exists when an answer will facilitate the decisional process, help resolve complex issues, clarify the issues in dispute or a party's position on the issues, lead to a more accurate and complete record or provide useful and relevant information which will assist in the decision making process. *East Tennessee Natural Gas Company*, 79 FERC ¶ 61,124 at 61,569 (1997); *Great Lakes Gas Transmission, L.P.*, 66 FERC ¶ 61,115 at 61,194 (1994); *Tennessee Gas Pipeline Company*, 55 FERC ¶ 61,437 at 62,306 n.7 (1994); *Transwestern Pipeline Company*, 50 FERC ¶ 61,362 at 62,090 n.19 (1980); *Transwestern Pipeline Company*, 50 FERC ¶ 61,211 at 61,672 n.5 (1980).

bidding. Further, the ISO's proposal will provide for improved congestion management and price transparency by utilizing a full-network model and locational marginal pricing (LMP). As the ISO indicated in its MD02 Filing, its MD02 proposal is conceptually consistent with the Commission's "Working Paper on Standardized Transmission Service and Wholesale Electric Market Design" (SMD Working Paper) issued on March 15, 2002. MD02 Filing at 23, Attachment A at 24-33, Attachment T. No intervenor appears to challenge this fact.

As proposed by the ISO in its MD02 filing, the ISO would implement the MD02 proposal in three phases. Phase I (with a proposed effective date of October 1, 2002) includes market power mitigation measures designed to prevent physical and economic withholding, a residual unit commitment (RUC) process, a modified Must Offer Requirement, real time economic dispatch, use of a Single Energy bid curve, penalties for failure to comply with schedules, as modified by Dispatch instructions, a rolling 12-month Market Competitiveness Index (12-month MCI) and a cap on decremental bids.[2] In its MD02 Filing, the ISO advocated extension of the existing west-wide price mitigation scheme beyond September 30, 2002. In the alternative, the ISO proposed that the Commission adopt a damage control bid cap (DCBC) of $108/MWh and automated mitigation procedures (AMP)

Phase II – which has a target date of Spring 2003 – would include, *inter alia*, elimination of the market separation rule and balanced schedule requirement and implementation of simultaneous Congestion Management,

[2] The ISO also proposed to implement certain locational market power mitigation measures with an effective date of July 1, 2002.

Energy market, Ancillary Services procurement and unit commitment on a zonal basis. Phase III – which has a target effective date of Fall 2003 – involves implementation of full network model, redesigned firm transmission rights (FTRs) and an integrated Congestion Management, Energy and Ancillary Services market based on LMP.[3]

The MD02 Filing included the revisions to the ISO Tariff necessary to implement the Phase I elements of MD02. The ISO stated that it would file tariff language for the Phases II and III elements in mid-June.[4] The ISO indicated that it would then commence a series of technical conferences with stakeholders to explain the proposed tariff revisions, receive comments from stakeholders and make any necessary revisions to the Tariff. The ISO requested that the Commission issue an order by July 1, 2002 accepting the Tariff provisions for the Phase I elements and granting preliminary conceptual approval of the Phases II and III elements. Approval of the Phase I elements by July 2002 is necessary because the ISO anticipates that it will take at least three months to implement certain of the Phase I elements. Conceptual approval of the long-term elements by July 2002 is imperative because Phases II and III will require extensive software and systems development and testing. The ISO anticipates that it will need a lead-time of approximately 12-18 months to procure, install and adequately test the new software and systems before they become fully operational. The ISO committed that, following the stakeholder process, it would

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[3] The ISO also proposes to impose an available capacity (ACAP) obligation on Load Serving Entities (LSES) commencing January 1, 2004.

[4] The ISO is filing simultaneously herewith the Phases II and III tariff language.

promptly submit any necessary tariff revisions so that the Commission would be able to issue a final order early in the fall.

More than 40 parties filed motions to intervene in the instant proceeding. Most of these motions to intervene include protests and/or comments concerning the MD02 Filing. The ISO's Answer will discuss the following matters: (1) the ISO will address comments and protests regarding the Phase I elements; (2) the ISO will provide any necessary clarifications regarding the Phase I elements; and (3) the ISO will address comments and protests which raise "conceptual" issues regarding the Phases II and III elements. There are several reasons why the ISO is only discussing "conceptual" issues with respect to the Phases II and III elements. First, the ISO is submitting, in a separate filing, detailed tariff language for the Phases II and III proposals. Second, the ISO is committed to an intensive stakeholder process regarding the Phases II and III proposals and is prepared to file revised tariff language as a result of that process. Third, the ISO is requesting that the Commission approve the market design "concepts" in a July order and approve tariff language for the Phases II and III elements prior to the fall.

Given the time limitations and the approach outlined above, the ISO notes that it is only addressing certain of the claims raised by intervenors. Any omission should not be construed as the ISO's agreement to the objection raised or as a waiver of the ISO's right to contest the issue at a later date. The ISO submits that no party has raised issues that require rejection of or revisions to (1) the Phase I elements proposed by the ISO or (2) the "concepts" upon which the

Phases II and III market redesign are based. The ISO also notes that it has pushed its resources to the limit in order to answer protests promptly as well as put together the Tariff filing for the MDO2 Phases II and III elements. Any failure on the part of the ISO to address fully each and every issue raised in the late-filed protests should not be construed by the Commission as acquiescence to such protests.

With respect to the process after June 14, 2002, the ISO recognizes that parties need to be given adequate time to digest and comment on the ISO's proposed tariff language, and the ISO needs to have time to respond to any protests and provide any necessary clarifications. Later this summer, the ISO recommends that the Commission sponsor a one-week-long, intensive stakeholder process to address the outstanding issues regarding the Phases II and III elements and seams issues[5] and attempt to reach consensus on such elements. The ISO notes that the Electric Power Supply Association (EPSA) also supports a week-long conference. EPSA at 7. Prior to such Commission-sponsored conference, the ISO will attempt to meet with stakeholders to narrow the issues. Following the stakeholder process, the ISO will file any necessary Tariff provisions in order to facilitate prompt Commission approval (and ISO implementation) of a new market design.

B. It Would Be Arbitrary and Capricious for the Commission to Terminate the Existing West-Wide Price Mitigation on September 30, 2002

5 The ISO notes that it has been working with its regional partners RTO West and WestConnect via the Seams Steering Group-Western Interconnection (SSG-WI) to address seams issues.

In its June 19, 2001 order in Docket No. EL00-95, *et al*., the Commission ruled that the west-wide price mitigation scheme would terminate on September 30, 2002. *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*, 95 FERC ¶ 61,418 at 62,549 (2001) ("June 19 Order"). Facts that have come to light in the past couple of months (as well as certain other factors) require that the Commission extend the existing price mitigation measures beyond September 30, 2002. However, beyond the specific market conditions and procedural reasons described below, there is a more basic reason to continue the current mitigation regime related to the overarching policy goal of establishing seamless regional power markets.

Due to the events of the past two years, the consumers and ratepayers of California – the largest power market in the western region – have suffered a crisis of confidence in the ability of competitive power markets to provide real benefits. This crisis of confidence has in turn created an atmosphere of uncertainty and stimulated political debate regarding the optimal industry structure and regulatory framework for California. And while such debate is a natural and vital response to the power crisis, the resulting uncertainty has tended to have a stifling effect on investment. Contrary to the assertions of some intervenors that the Commission's mitigation rules have discouraged investment, the ISO would assert that uncertainty regarding the future market rules and regulatory framework has been the greatest contributor to the recent spate of project postponements and the generally cautious climate in the investment community.

What California needs most now is a period of stability that is not bounded by an arbitrary cut-off date, to allow adequate time for state and federal policy makers to work collaboratively to assess the alternatives and resolve the persistent crisis conditions that still exist. In the ISO's comments in response to the Commission's Operational Audit, the ISO stated:

> Among all the recommendations in the Audit, the CA ISO believes that there is none more important than the call for "jurisdictional cooperation." If this is to occur the CA ISO believes that it is imperative that the commission restore the State's perception that the Commission will take all necessary actions to protect the public interest.[6]

Over the past few months Commission staff have contributed significantly to "jurisdictional cooperation" by sponsoring and attending working sessions with California stakeholders regarding ISO market design. However, even with today's filing of the ISO's Market Design 2002 (MD02) Tariff changes, there is much work remaining to be done that will require continued dialogue and collaboration between state and federal policy makers.

The Commission clearly understands, through its ongoing activities to develop Regional Transmission Organizations (RTOs) and define a Standard Market Design (SMD), that these important policy initiatives will have long-term impacts and benefits, and that the decades-long ways of doing business in the power industry cannot be changed over night. Indeed, California set out enthusiastically in the mid 1990s to lead the nation in its embrace of competitive

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[6] Comments of the California Independent System Operator Corporation on the Commission's Operation Audit of the CA ISO, February 15, 2002, page 4.

electric industry restructuring, and established an industry design that was unprecedented in its dependence on competitive markets. When such an effort results in such severe problems there is inevitably a backlash, including questioning of and withdrawal from the principles on which the great experiment was founded.

The ISO urges the Commission to acknowledge that rebuilding confidence after the energy crisis has cost California and the West tens of billions of dollars is not simply a matter of climbing back in the saddle and jumping the same hurdle again. It will take time, during which the Commission's mitigation scheme is needed to maintain stability while California carefully rebuilds confidence in market approaches to electric power supply and procurement.[7] The ISO urges the Commission also to acknowledge – as the ISO's June 17 MD02 Tariff Filing will bear witness to – that the ISO has in good faith developed a comprehensive and effective redesign of its markets, and that the implementation of this design will be complex and will take time. Finally, the ISO urges the Commission to recognize that some of the crisis conditions – particularly the bankruptcy and

[7] In this regard, the history of PJM is an important but frequently overlooked chapter in the annals of electric restructuring. The ISO is particularly perplexed in this regard by those intervenors who urge the ISO and the Commission simply to install the PJM market design in California without modification, since it has been proven to work. The absurdity of this argument is that it ignores essential ingredients in PJM's success, namely, its long history of cooperation across multiple utility control areas and states as a tight power pool, and its gradual approach to implementing market-based system. These intervenors seem to forget that when PJM first began operation as an ISO it had only a single settlement system (all settlements were based on real-time prices and quantities), and all suppliers operated under cost-based rates. After one year of such operation PJM introduced market-based rates. After a second year it introduced a forward (day ahead) settlement and a forward market for Regulation. It is now developing a forward market for Operating Reserves. The PJM example stands in stark contrast to both California's pre-restructuring framework, in which interdependence among utilities was much more limited, and its aggressive restructuring program. The ISO urges the Commission to keep these facts in mind when it considers the arguments of intervenors who urge the ISO to jump quickly back in the market saddle or to simply implement PJM in California.

near bankruptcy of the state's largest utilities, which has caused the state to play a major role in power procurement – cannot be resolved on an imposed timetable.[8] For all these reasons, the ISO believes that the Commission's optimal course of action at this time, for the sake of the long-term objective of establishing a regional power market in which California is a fully engaged participant, is to do everything possible to create and maintain market stability, which in turn will allow federal and state policy makers to establish sustainable structures and rules that have minimum risk of being overturned later in response to another crisis. Such stability and regulatory certainty are prerequisites for an attractive investment climate. The Commission should therefore extend the existing mitigation regime and approve the other "October 1st Elements" of the May 1 Filing as proposed by the ISO (except, of course, where the existing mitigation makes the new element unnecessary, as indicated in the May 1 Filing).

Finally, the ISO frankly wonders why some intervenors in the supply community appear not to recognize the relationship between investor confidence and regulatory certainty, and persistently argue that California must rely on market mechanisms to the greatest extent possible as soon as possible. The ISO believes that it should be in the best interest of all parties to create a long-term sustainable industry structure that will promote workable competition to the benefit of all suppliers and consumers. These intervenors need to acknowledge the difficulties involved and the time needed to create a sustainable market structure, particularly given California's experience, and should advocate and

[8] California's initial restructuring effort was designed and implemented on a politically-imposed timetable. The ISO believes this fact alone is one of the more salient "lessons learned" regarding the redesign of an entire industry.

embrace Commission policies that will maintain stability during this important transition.

These reply comments now turn to some specific circumstances that argue for the Commission to extend the existing price mitigation beyond September 30, 2002. First, as discussed in greater detail below, the Commission has been presented with evidence of "gaming" and manipulation in California's energy markets. Second, the Commission is in the middle of a comprehensive fact-finding investigation regarding the extent of "gaming" and manipulation in California's energy markets, and the scope of the investigation is expanding every day. Third, in its several orders approving price mitigation for California's energy markets, the Commission identified numerous structural flaws that it claims were responsible, in part, for the dysfunctional market in California and the unjust and unreasonable prices charged California consumers. The MD02 Filing addresses these market design flaws; however, the market redesign proposal will not be fully implemented until the fall of 2003. Fourth, the Commission has identified several "generic" steps that it is undertaking that it has said will prevent seller from exerting market power in California (and other markets); however, such steps have not been implemented and, in all likelihood, will not be implemented by September 30, 2002. Fifth, the supply-demand imbalance in California has not improved to the point where workable competition can be assured, particularly if hydro conditions worsen in 2003. Sixth, California's two largest investor owned utilities, representing approximately 80 percent of the ISO's Control Area load, remain sidelined from participation in the ISO's markets due to credit concerns, and a State entity with very little regulatory authority is purchasing energy on their behalf. These and other factors require that, at a minimum, the Commission extend the existing price mitigation until such time as these issues are resolved.[9] The intervenors opposed to extension of the west-wide mitigation have not raised any arguments that justify termination of the west-wide mitigation on September 30, 2002.

1. The Commission Should Not Terminate the West-Wide Price Mitigation Until All Investigations and Complaint Proceedings Regarding Market Power and Market Manipulation in California are Completed and the Commission Finds That the California Market is Workably Competitive

On February 13, 2002, the Commission initiated a Fact- Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices in the Western U.S. 98 FERC ¶ 61,165 (2002). The Commission's intent was to:

> gather information on whether any entity, including Enron Corporation (through any its affiliates or subsidiaries), manipulated short-term prices for electric energy or natural gas in the West or otherwise exercised undue influence over wholesale electric prices in the West, since January 1, 2000, resulting in potentially unjust and unreasonable rates in long-term power sales contracts subsequently entered into by sellers in the West.

Id. at 61,614. The Commission indicated that it would use the information discovered in this fact-finding investigation to determine how to proceed on any existing or future complaints under Section 206 of the Federal Power Act (FPA) involving long-term power sales contracts relevant to the matters investigated or any formal FPA Section 206 proceeding. *Id.*

[9] In particular, the west-wide mitigation needs to remain in place to protect against the practice of "megawatt laundering." As the Commission recognized in its May 15, 2002 "Order On Rehearing And Clarification" issued in Docket Nos. EL00-95-053, *et. al.*, "megawatt laundering "is still a concern.

In connection with this investigation, on May 6, 2002, the Commission made public three memoranda detailing numerous Enron Corporation strategies some of which are clearly intended to "game" and/or manipulate the energy market in California.[10] The Enron Memos also expressly state that other market participants have employed some of the same strategies identified in the Enron Memos, i.e. "inc-ing load" and "relieving congestion."

In response to the Enron Memos, on May 7, 2002, the Commission issued a notice that its Staff in the near future would issue data requests to all sellers of wholesale electricity and Ancillary Services to the ISO and/or California Power Exchange (PX) during the period 2000-2001 concerning such sellers' engagement in the "trading strategies" identified in the Enron Memos. On May 8, 2002, the Commission issued data requests to all sellers of wholesale electricity and Ancillary Services to the ISO and PX concerning their involvement in the "gaming" and/or market manipulation activities identified in the Enron Memos. Then, on May 21, 2002, the Commission expanded the scope of the investigation by serving data requests on all sellers of wholesale electricity and Ancillary Services in the U.S. portion of the Western Systems Coordinating Council (WSCC) during 2000-2001 regarding their participation in "wash," "round trip" or "sell/buyback" trading. The Commission indicated that it was requesting the

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[10] The Commission released the following memoranda: (1) a December 6, 2000 memorandum from Christian Yoder (of Enron Power Marketing, Inc.) and Stephen Hall (of Stoel Rives, LLP) to Richard Sanders (of Enron) titled, "Traders' Strategies in the California Wholesale Markets/ISO Sanctions"; (2) a December 8, 2000 memorandum from Christian Yoder and Stephen Hall to Richard Sanders also titled, "Traders' Strategies in the California Wholesale Markets/ISO Sanctions"; and (3) an undated memorandum from Gary Fergus (of Brobeck, Phleger & Harrisson, LLP) and Jean Frizzell (of Gibbs & Brans, LLP) to Rich Sanders titled, "Status Report on Further Investigation and Analysis of EPMI Trading Strategies," (referred to collectively as the "Enron Memos").

information because of inconsistent financial transaction data already submitted by some companies as part of the Commission's investigation. The Enron Memos are evidence of "gaming" and market manipulation in the California energy market. Commission Chairman Pat Wood III testified that such practices are "clearly wrong". *Inside FERC* at 1 (May 20, 2002). Moreover, a strong possibility exists that other suppliers in the California market have engaged in similar gaming and/or market manipulation.

The Enron Memos and the Commission's investigation in Docket No. PA02-2-000 come on the heels of complaints that have been filed with the Commission alleging that sellers of energy in the California market have exercised market power in certain of their long-term power sales contracts. Specifically, in Docket Nos. EL02-60-000 and EL02-62-000, the California Public Utilities Commission (CPUC) and the California Electricity Oversight Board (EOB), respectively, have filed complaints against sellers of energy and capacity pursuant to long-term contracts with the California Department of Water Resources (DWR) alleging that such contracts are unjust and unreasonable because of market design flaws and sellers' exercise of market power in connection with such contracts. The Commission recently set these complaints for expedited evidentiary hearing. *Public Utilities Commission of the State of California v. Sellers of Long-Term Contracts to the California Department of Water Resources, et al.*, 99 FERC ¶61,087 (2002).

The significance of these ongoing proceedings regarding market manipulation and the exercise of market power in California's energy markets cannot be downplayed given that the Commission has expressly found **on several occasions** that prices in California's wholesale electric market were unjust and unreasonable and, as a result, imposed market mitigation measures and conditioned suppliers' market-based rate authority. *See, e.g., San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services into the Markets Operated by the California Independent System Operator and the California Power Exchange*, 93 FERC ¶ 61,294 at 61,998 (2000) ("December 15 Order"); 95 FERC ¶ 61,115 at 61,351, 61,360 (2000) ("April 26 Order"); June 19 Order at 62,549, 62,565; 97 FERC ¶ 61,275 at 62,218 (2001) ("December 19 Order"). The Commission has not made any subsequent findings that, absent the current mitigation methodology (1) the California wholesale electricity market would produce rates that are just and reasonable, (2) the flawed market structures and supply-demand imbalance it identified as causes of such prior unjust and unreasonable prices have been corrected, (3) competitive market conditions exist, and (4) suppliers can not exercise market power or "game" or manipulate the market.[11] Indeed, in his comments before the United States Senate Committee on Commerce, Science and Transportation, Subcommittee on Consumer Affairs, Foreign Commerce and Tourism on May 15, 2002, Chairman Wood stated, "[i]t is clear that all the conditions for a successful competitive market are not likely to be existing by that time [i.e. September 30, 2002]."

[11] The ISO also has submitted a series of reports to the Commission demonstrating both the exercise of market power by individual sellers of electricity and anticompetitive bidding behavior. *See* First Quarterly Update of the California Independent System Operator Corporation, Docket Nos. EL00-95-000, *et al*., (September 14, 2001); Second Quarterly Update of the California Independent System Operator Corporation, Docket Nos. EL00-95-000, *et al*., (December 14, 2001); Third Quarterly Update of the California Independent System Operator Corporation, Docket Nos. EL00-95-000, *et al.,* (March 26, 2002).

Given that the Commission has found that prices for electricity were unjust and unreasonable in California, the indisputable evidence that "gaming" and market manipulation have occurred in California and allegations that sellers have exercised market power under their long-term contracts, it would be arbitrary and capricious for the Commission to terminate the west-wide mitigation on September 30 if the following circumstances have not occurred: (1) the Commission has completed its investigation in Docket No. PA02-2-000 regarding market manipulation in California's electricity markets; (2) the proceedings in Docket Nos. EL02-60, *et al.* regarding the exercise of market power by sellers of electricity under long-term contracts have concluded; and (3) the Commission has found that (a) no "gaming" and/or market manipulation is occurring in the California market and the ISO's proposed market corrections have been approved and implemented, (b) sellers have not exercised market power under their long-term sales contracts with DWR, (3) prices in California's wholesale electricity market are just and reasonable, and (4) workable competition exists and can reasonably be expected to continue to exist in the California market.[12]

2. The Commission Should Retain the West-Wide Mitigation Until the Necessary Structural Reforms and Market Rules Are in Place

In its November 1, 2000 "Order Proposing Remedies for California Wholesale Electric Markets" in Docket No. EL00-95-000, *et al.*, the Commission

[12] On April 24, 2002, the ISO's Department of Market Analysis (DMA) filed "Comments Regarding The Federal Energy Regulatory Commission's Proposed Market-Based Rate Standard and Mitigation Mechanism" in Docket Nos. RM01-012. These Comments included DMA's assessment of suppliers' ability to exercise market power using a Residual Supply Index (RSI) test. The RSI test showed that each of the five major suppliers in the California market are pivotal for a significant number of hours during the year. *See also* MD02 Filing, Attachment R at 12-13 (Affidavit of Gregory Cook).

found that the electric market structure and market rules for wholesale sales of electricity in California were seriously flawed, and such structures and rules, in conjunction with an imbalance of supply and demand in California, "have caused, and continue to have the potential to cause unjust and unreasonable rates for short-term energy." [13] *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*, 93 FERC ¶ 61, 121 at 61,349(2000) ("November 1 Order"). The Commission stated that there was clear evidence that the market structure and rules provide the opportunity for sellers to exercise market power when supply is tight and can result in unjust and unreasonable rates. *Id.* at 61,350. The Commission ordered that a number of structural reforms be implemented including (1) establishment of generation interconnection procedures, (2) the submission of a congestion management redesign proposal, (3) improved market monitoring and market mitigation strategies, (4) demand response programs by the ISO and Scheduling Coordinators, (5) elimination of the requirement for balanced schedules, and (6) a new approach to reserve requirements. *Id.* at 61,350-51. The Commission recognized that these and other steps were **necessary** to ensure a well-functioning wholesale market in California. *Id*. In particular, the Commission stated "[t]o ensure fair prices while these market reforms are being put in place, the order proposes additional temporary measures to mitigate prices…" *Id.* at 61,351.

[13] The Commission repeated these findings in its June 19 Order approving the west-wide mitigation measures. June 19 Order at 62,549. The June 19 order also recognized that the California market was dysfunctional. *Id.* at 62,546.

At this time, all of the aforementioned structural reforms identified in the November 1 Order have not been implemented. Many of these reforms are addressed in the MD02 Filing; however, the MD02 proposal will not be fully implemented until the fall of 2003, with the ACAP obligation not becoming effective until January 1, 2004. Other reforms either are pending Commission action or will be filed in the near future. Given that the Commission has expressly stated that mitigation is necessary until the aforementioned market reforms have been implemented, the ISO submits that it would be arbitrary and capricious for the Commission to terminate the existing price mitigation before such market structure reforms are implemented. Thus, at a minimum, the Commission must retain the west-wide price mitigation until such time as the ISO's MD02 proposal is fully implemented. The ISO will now briefly discuss the ISO's attempts to address the structural problems identified by the Commission in the November 1 Order.

In the November 1 Order, the Commission stated that the ISO needed to file procedures to facilitate the interconnection of new generators. November 1 Order at 61,364-65. On April 2, 2001, the ISO filed Tariff Amendment No. 39 in Docket No. EL00-98-023 in which the ISO proposed enhanced new generator interconnection procedures. On April 24, 2002, in Docket No. RM02-1-000, the Commission issued a Notice of Proposed Rulemaking (NOPR) regarding standardization of generation interconnection agreements and procedures. Initial comments on the NOPR are due on June 17, 2002. It is uncertain when the Commission will issue a final rule. On June 4, 2002, the Commission issued an order on the ISO's Amendment No. 39 filing. The Commission accepted and suspended the filing, subject to refund, and subject to further Commission action in the generator interconnection NOPR proceeding.

In the November 1 Order, the Commission also directed the ISO to consider what market rules are needed to ensure that sufficient supply is available to meet loads and reserve requirements. November 1 Order at 61,365. Consistent with this directive, the ISO has proposed, in its MD02 filing, an available capacity (ACAP) obligation on load serving entities (LSEs) that would require LSEs to procure in a forward timeframe resources sufficient to satisfy their forecast load for a given month, plus a reserve margin. MD02 Filing, Attachment A at 44-77. However, because two of the three investor-owned utilities (IOUs) in California are not yet creditworthy (and, once creditworthy, they will need adequate lead-time to procure long-term resources) the ISO has proposed a January 2004 effective date for its ACAP proposal. In its June 19 Order approving the west-wide mitigation, the Commission stated that "[w]hile progress has been made in correcting market dysfunctions, the dysfunctions will not be fully corrected until additional load is moved from the spot market to longer-term contracts (a mixed portfolio of supply contracts) and the basic structural defect of inadequate supply in the West is corrected." [14]June 19 Order at 62,546. The Commission also stated "the cornerstone of remedying the dysfunctions in the energy markets in the West…is eliminating California's excessive reliance on spot markets." *Id.* at 61,347. The ACAP proposal is

[14] Although the long-term contracts signed by the State have helped reduce spot market exposure, as shown in the ISO's Third Quarterly Report (pp. 89-90) and the Affidavit of Gregory Cook (MD02 Filing, Attachment R at 11), significant spot market exposure still remains.

intended to address this very issue. Given that the Commission has found the lack of long-term contracting and lack of adequate supplies to be the cornerstone of California's problems, any Commission decision to terminate the west-wide mitigation before these problems are adequately addressed would not be the product of reasoned decision making.

In the November 1 Order, the Commission expressed concern that under-scheduling problems in California may be the result of the ISO's balanced schedule requirement. November 1 Order at 61,365. The Commission directed the ISO to consider establishment of an integrated day-ahead market in which all demand and supply bids are addressed in one venue. In its MD02 Filing, the ISO proposes to eliminate the balanced schedule requirement effective Spring 2003. Also in Spring 2003, the ISO will implement on a zonal basis an integrated day-ahead market. The ISO proposes to implement an integrated day-ahead market on a nodal basis in fall 2003. A day-ahead energy market should help reduce reliance on spot market transactions that the Commission found was a significant contributing cause to the problems in California. This is another reason why the Commission should wait for implementation of MD02 before terminating the west-wide mitigation.

The Commission also directed the ISO to consider imposing "less intrusive, narrowly tailored market protection mechanisms," *i.e.*, mechanisms that would "take the form of the *ex ante* identification of conditions of behavior that would trigger specific market mitigation actions." November 1 Order at 61,365. The Damage Control Bid Cap, AMP and 12-month MCI proposed in the MD02

Filing meet these requirements. However, the ISO is only proposing the DCBC and AMP as alternatives in the event the Commission decides to terminate the west-wide price mitigation on September 30, 2002. As indicated in the MD02 Filing, the ISO believes that the existing price mitigation scheme is a more effective tool to ensure just and reasonable rates and should remain in place until all pending investigations/hearings are concluded, the MD02 proposal is fully implemented and the Commission finds -- based on substantial record evidence-- that a workably competitive market exists in California and can reasonably be expected to exist in the foreseeable future. The ISO also notes that later this summer it will make a tariff filing to enhance its market monitoring and investigation authority. Consistent with the directives in the November 1 Order, the ISO will identify specific conditions or behavior that would trigger specific market mitigation actions or penalties.

The Commission also found that the ISO's congestion management structure was flawed, and the Commission directed the ISO to file a comprehensive congestion management redesign. November 1 Order at 61,365-66. Although the Commission stated that the existing congestion management structure was not a significant cause of the high prices experienced during the summer of 2000, the Commission viewed congestion management redesign as "crucial." *Id.* The ISO has proposed a new congestion management redesign in its MD02 Filing. Effective fall 2003, the ISO proposes to implement a nodal congestion management structure with locational marginal prices at the node level.

In the November 1 Order, the Commission also directed the ISO to consider implementing demand bidding programs in which load can bid offers of demand reduction directly into the market to compete with offers of supply. November 1 Order at 61,366. In its June 19 Order, the Commission stated "establishing a demand response mechanism is crucial to establishing a robust market." June 19 Order at 62,555. The MD02 Filing accommodates demand-side bidding, including the option to submit multi-part bids. This element of the MD02 proposal will be fully implemented until Fall 2003. MDO2 Filing, Attachment A at 118. Given that the Commission has stated that demand participation in the market is "crucial" to the development of a well-functioning market, it would seem illogical and arbitrary to terminate the west-wide mitigation before the demand participation mechanisms in the MD02 Filing are implemented.

Finally, the Commission stated that many of the problems confronted in California can be traced to the balkanization of the western grid. November 1 Order at 61,366. Commencing in June of 2001, the ISO, RTO West and WestConnect initiated discussions to address interregional coordination and seams issues and these discussions are continuing. The Commission has not yet found that any of the western regional transmission organizations is in compliance with Order No. 2000 (indeed RTO West and WestConnect are not even operational as of this date) and seams issues have not yet been fully resolved. The benefits to consumers that the Commission identified in the

November 1 Order will not be available until RTOs throughout the west are fully operational.[15]

In conclusion, in various orders, the Commission has identified several market defects that contributed, in part, to the dysfunctional market in California and led to unjust and unreasonable prices. The Commission ordered the ISO to implement certain market redesign measures in order to help restore long-term stability to California's wholesale electricity market. The ISO proposes to implement many of these market design changes in its MD02 Filing. Further, the MD02 Filing includes an integrated set of market monitoring and mitigation proposals to deter the exercise market power and the types of "gaming" and market manipulation activities identified in the Enron Memos.[16] However, the MD02 market design elements will not be fully implemented until fall 2003, and the ACAP proposal will not be implemented until January 2004. This is important because the ISO's ACAP proposal will promote long-term contracting and foster generation investment in the California market, thereby addressing one of the major "dysfunctions" in California's wholesale electricity market. Similarly,

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[15] In its November 1 Order, the Commission also recognized that to resolve the problems facing California consumers, the CPUC should address the following issues: (1) delays in siting generation and transmission lines; (2) implementation of additional retail demand response programs; and (3) elimination of impediments on LSE's procuring power supplies on a forward basis. On October 29, 2001, the CPUC issued a rulemaking in Docket No. 01-10-024 to establish guidelines for the states' IOUs procurement of electric energy, capacity and ancillary services. A decision is expected in October 2002. It is clear that issues surrounding the long-term procurement of supplies –an issue that the Commission believes is fundamental to resolving the problems in California—will not be resolved by September 30, 2002. It would clearly be arbitrary and capricious for the Commission to terminate the west-wide mitigation before this problem is resolved in a satisfactory manner.

[16] Under the MD02 market design, the financial incentives to "play" many of the Enron "games" will not exist. However, as discussed above, MD02 will not be fully implemented until fall 2003.

demand bidding on a nodal basis -- which the Commission has stated "is crucial to establishing a robust market"-- will not be implemented until fall of 2003.

The ISO submits that it would be illogical, arbitrary and capricious for the Commission to terminate the west-wide mitigation on September 30, 2002 when two of the primary market dysfunctions that necessitated such price mitigation will not be corrected by that date. Likewise, other market design problems that the Commission found were partly responsible for dysfunctions in California's wholesale energy market will not be corrected by September 30, 2002. Moreover, market standardization and new market power assessment standards -- which the Commission has stated will help ensure reasonable rates in wholesale electricity markets – will not be in place by that date. [17] Under these

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[17] The ISO also notes that, in its December 19 Order, the Commission stated that it was taking steps to ensure that sellers lack market power or cannot benefit from any market power they might temporarily possess. Specifically, the Commission noted that it was in the process of (1) completing the work of separating operation of transmission and generating facilities, (2) ensuring that sellers with market-based rates cannot benefit from engaging in anticompetitive behavior and (3) standardizing wholesale market rates. December 19 Order at 62,173. The Commission stated that it believed such steps would ensure that wholesale rates for the sale of electricity remain just and reasonable. *Id.* On November 20, 2001, the Commission initiated a proceeding in Docket No. EL01-118 in which it proposed to revise existing market based rate authorizations and condition new market based rate authorizations to ensure that rates do not become unjust or unreasonable as a result of anticompetitive behavior or abuse of market power. *Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations*, 98 FERC ¶ 61,220 at 61,975. (2001). The Commission also indicted that it would solicit comments to "inform" a generic rulemaking proceeding on potential new analytical methods for assessing markets and market power. *Id*. The Commission expressly stated that the events in California made it necessary and appropriate to impose tariff conditions on sellers with market-based rate authority. The Commission has not yet issued a final order in Docket EL01-118 and has not initiated any rulemaking regarding new standards for market power assessment. The ISO notes that the Commission has found the "hub-and-spoke" test which was used to grant market-based rate authority to suppliers in California is inadequate, and, therefore, there is no analytical predicate for the Commission to assume that western suppliers lack market power at all times and under all conditions. *See AEP Power Marketing, Inc. et al,*, 97 FERC ¶ 61,219 (2001).

With respect to the Commission's stated goal of standardizing market rules, on March 15, 2002, the Commission issued its SMD Working Paper. On April 10, 2002, the Commission issued a paper titled "Options for Resolving Rate and Transition Issues in Standardized Transmission Service and Wholesale Electric Market Design." ("Options Paper") The Commission has not yet issued a notice of proposed rulemaking on standardized market design; thus, it is unlikely that any final rule would be issued until sometime in 2003. Thus, two of the tools that the circumstances, there is no rational basis for the Commission to terminate the west-wide price mitigation on September 30, 2002. Rather, the only reasonable and justifiable approach is for the Commission to leave the existing price mitigation measures in place at least until the MD02 proposal is fully implemented.

3. Market Conditions In California Have Not Improved To the Point Where the Commission Can Terminate the West-Wide Mitigation

Suppliers uniformly oppose the ISO's request that the Commission extend the existing west-wide mitigation beyond September 30, 2002. EPSA alleges that many of the conditions that led the Commission to conclude that mitigation was necessary no longer exist. EPSA at 9. IEP and Reliant note that prices in the real time energy markets generally have been below the price cap, and this constitutes evidence that prices are being restrained by fundamental market forces, and mitigation is not necessary. IEP at 7; Reliant at 6. IEP and EPSA state that additional generation has come on-line in California and neighboring states. IEP at 7; EPSA at 9. IEP and EPSA also note that hydroelectric resources are at significantly higher levels. IEP at 7; EPSA at 9. IEP states that there are some creditworthy buyers in California, demand reduction efforts remain in place and the economy is no longer growing as fast as before. EPSA also indicates that the size of the real time market has fallen to five percent of the forecasted load. EPSA at 9.

As an initial matter, the ISO desires to address the comments filed by Dynegy. Dynegy accuses the ISO of seeking to "over-mitigate the market that the

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Commission believes will ensure just and reasonable rates in California and other U.S. wholesale electricity markets are not yet in place.

underlying causes of the California energy problems go unresolved." Dynegy at 3. Dynegy alleges that MD02 fails to address most of the root causes of California's electricity crisis. *Id.* at 5. Dynegy's comments beg the following question: if the underlying causes of California's energy crisis have not been resolved – and are not resolved by the MD02 Filing—then why is it appropriate or justifiable to terminate the existing price mitigation?

In its November 1 Order and in subsequent orders, the Commission indicated that the imbalance of supply and demand in California was a cause of the unjust and unreasonable prices experienced in California. November 1 Order at 61,349. The Commission also recognized this fact in its June 19 Order approving the west-wide mitigation. June 19 Order at 62,546, 62,549. The Commission has not subsequently found—nor can it find—that the supply-demand imbalance that contributed to the energy crisis in California has been corrected. Any Commission decision terminating the west-wide mitigation cannot be sustained until the Commission finds that the supply-demand imbalance that resulted in unjust and unreasonable prices has been corrected, and such finding is supported by substantial evidence. No party has submitted an iota of evidence that the underlying supply-demand imbalance in California has been corrected. The undeniable fact is that supply-demand imbalance has not been corrected, and that is why continuation of the west-wide mitigation measures is necessary. Further, other factors that led to the unjust and unreasonable prices experienced in 2000 and 2001 have not improved sufficiently to provide a reasonable assurance that California's electricity markets will produce the just and reasonable prices that a truly robust and competitive market would produce.

With respect to IEP's and Reliant's claims that competitive market forces have restrained prices and a price cap is unnecessary, the ISO poses the following question: if prices are not hitting the price cap due to competitive forces (and not due to the price cap), then why is it such a problem to keep the price cap in place? Likewise, if the price cap is not constraining prices, then how can IEP and Reliant argue in good faith that price caps are hampering investment in new generation in California?

The ISO believes that price mitigation is needed at least as a backstop. The chart in Attachment A hereto shows price cap hits in California since June 2001. The chart shows that in November 2001, the price cap was hit in more than 20 percent of the BEEP intervals. November is generally a period where there are low hydro reserves.[18] As Attachment A also shows, there were three other months when prices were within one dollar of the cap in more than 20 percent of the BEEP intervals. Thus, the chart in Attachment A demonstrates that mitigation is still a necessary feature in the ISO's energy markets because the price cap will be hit during periods when supplies are tight, and such conditions occur quite frequently. This is consistent with the Commission's

[18] IEP notes that hydro reserves are up this summer. This summer is not the problem because the west-wide mitigation will still be in effect. The real problem arises when hydro reserves are low and there is not adequate mitigation in place. The surplus hydro reserves also account to some degree for the lower prices experienced in 2002. If hydro reserves were not at such levels, California likely would be experiencing higher prices. Even Dynegy recognizes in its protest that prices in California are impacted by the amount of available hydropower and that prices rises when water supplies are low. Dynegy at 18. The Commission is well aware that California cannot expect to have bountiful hydro reserves available year-in and year-out. That is why price mitigation is necessary until additional more non-hydro generation is constructed in California.

rationale in the June 19 Order that mitigation is needed during periods when reserves are low and sellers have the greatest ability to dictate price. June 19 Order at 62,546.

The ISO also notes that loads in spring 2001 were largely below levels seen in 2000 due to mild weather, a weak economy, conservation and involuntary curtailment during the crisis period of summer 2000 through spring 2001. However, the ISO has observed that loads in 2002 have increased since 2001. Warmer weather, modest economic rebound and conservation fatigue appear to be contributing factors. As discussed in Section O, participation in demand response programs this year is meager. Thus, IEP's claims that the economy is not growing and adequate demand reduction efforts are in place, are not correct. The California Energy Commission reports that peak demand, when adjusted for growth and weather conditions, increased 5.8 percent from April 2001 to April 2002. This is not an insignificant amount and suggests that the demand-supply balance could become much more tenuous in the not-too-distant future.

Finally, the ISO notes that, since the filing of its Third Quarterly Report, the status of new generation in California has continued to deteriorate. Between April 15 and June 1, 2002, only 100.5 MW of new generation has been brought on-line. More than 1,770 MW of generation either has been cancelled, withdrawn or put on indefinite hold after April15.[19] Further 653 MW have been retired or

[19] Generation development in all regions of the country has stalled in recent months. "*SERC Developing RTOs,Generation"* Energy Markets at 44 (May 2002). These nationwide generation delays are due to a cooler economic climate, financing problems due to debt downgrades and the Enron situation. *Id.*

offline due to environmental problems. These numbers are in sharp contrast to the Third Quarterly Report that indicated that 1,998 MW of new capacity was expected to be brought on-line by May 31, 2002. The ISO also has received indications that an additional 1,400 MW of generation in Southern California may be retired by the end of 2002 due to environmental regulations. Thus, the supply-demand balance has not fundamentally changed since the west-wide mitigation was imposed. Under these circumstances, the Commission must not arbitrarily terminate such mitigation.[20]

C. The Commission Should Reject Requests To Increase the Damage Control Bid Cap

1. A Higher Damage Control Bid Cap is Inappropriate Given the Structural Defects in California's Energy Market

Numerous suppliers argue that the Commission should approve a damage control bid cap ("DCBC") comparable to the DCBC that is in place in the eastern ISOs, *i.e.* $1000/MWh.[21] Mirant at 20; Duke at 14. Reliant supports a $500 MWh DCBC that would rise to $1,000 MWh in one year. Reliant at 21.

Although the eastern ISOs have a DCBC of $1000 per MWh, the ISO does not believe that this is an appropriate level for the California market due to the fact that the structural elements necessary to ensure a workably competitive

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[20] Although the size of the real time energy market in California has declined, Attachment A shows that even at this reduced level, there still are significant opportunities to brush up against the price cap. If the economy rebounds, the ISO experiences load growth, and the supply situation does not improve, the ingredients will be there for generators to exert their market power and charge unjust and unreasonable rates. That is why it is imperative that the Commission retain the west-wide mitigation after September 30, 2002.

[21] Dynegy takes a much more reasonable approach, suggesting a $250/MWh DCBC that could be increased annually by $250, assuming certain conditions are in place. The ISO agrees that as market conditions improve, the DCBC should be raised.

market do not exist in California. The ISO does believe that over time, as market conditions improve, the DCBC could eventually be raised to a level commensurate with the eastern ISOs. In no event should the DCBC automatically (and arbitrarily) be raised on a date(s) certain absent an evidentiary showing that more competitive conditions exist to justify such an increase.

The Commission has expressly found that the California wholesale energy market is dysfunctional and "seriously flawed." November 1 Order at 61,349; December 15 Order at 61,981; June 19 Order at 62,546. The Commission has expressly found the rates in California's wholesale energy market to be unjust and unreasonable. Further, the Commission has been presented with evidence of "gaming" and manipulation in the California energy market, and the Commission presently is conducting an investigation into the manipulation of energy prices in California. None of these circumstances exist in the eastern ISOs. The 2001 "Annual Report on the New York Electricity Markets" dated April 16, 2002 states at page two "[a]nalysis of the market conduct of both suppliers and the load-serving entities indicates that the markets have been workably competitive." The "PJM Interconnection State of the Market Report" dated June 2002 indicates at page one that "in 2001 the energy markets were reasonably competitive." A "Competitive Analysis of the Energy Market in New England" prepared by the Independent Market Advisor to ISO New England in May 2002 notes at page ii "New England markets have been workably competitive and produces little evidence of persistent economic or physical withholding." A $1,000/MWh DCBC may be justifiable in the eastern ISOs where workable competition exists. However, no party alleges that there is workable competition in California, and the Commission has not made such a finding. Accordingly, there is no basis to support imposition of a $1,000/MWh DCBC in California.

A significant difference between the ISO and the eastern ISOs is the supply-to-demand imbalance that exists in California. As indicated above, the Commission has recognized that there is inadequate supply in California. *See*, *e.g.*, June 19 Order at 62,546. The Commission has not made similar findings with respect to the eastern ISOs. In fact, the reserve margins in the eastern ISO's are considerably higher than the reserve margins in California. Because there is a supply-to-demand imbalance in California, there exists a greater opportunity for suppliers to exercise market power than exists in the eastern ISOs. Accordingly, there is a need for a significantly lower DCBC in California.

Moreover, as the Commission has recognized, the reliability of California's electric system depends in large part on imports from generation located in neighboring states to meet load requirements.[22] November 1 Order at 61,357. The eastern ISOs such as PJM do not have such a reliance on imports. *See "East vs. West: Comparing Electric Markets in California and PJM,"* Public Utilities Fortnightly, p. 26 (June 15, 2000) (recognizing that PJM is a self-contained system and California is a net importer of power). However, as indicated in the Affidavit of Gregory Cook (MD02 Filing, Attachment R at 8), to add to the supply concerns in California, the amount of energy bid into the ISO's real-time market has fallen dramatically due, in large part, to the requirement in the December 19 Order that markets and System Resources bid $0/MWh into

[22] California's import capability is approximately 8,000 MW.

the ISO's real-time market and be price takers.[23] Imports bid into the ISO's BEEP stack have remained relatively low through the Spring (and could diminish as northwestern runoff slows). The decline in imports bidding into the real time market makes California's supply-to-demand balance even more precarious and militates against approval of a high DCBC.[24] In that regard, the absence of competition from imports only creates more favorable conditions for in-state suppliers to exercise market power.

Another major structural difference between the ISO's markets and the markets in the eastern ISOs is the over-reliance on the spot market and the lack of forward contracting and capacity obligations. Unfortunately, for the reasons discussed above, this defect will not be cured in the immediate future. Although CERS has entered into long-term contracts for a significant amount of capacity, CERS is but a temporary placeholder for the utilities as its authorization expires at the end of the year. Moreover, CERS' firm contracts leave significant exposure to short-term purchases during peak periods. For example, based on loads similar to August 2001, CERS' portfolio covers on average, approximately only 70 percent of the IOU net short-load requirements during peak periods. Affidavit of Gregory Cook at 11. Thus, a significant amount of load remains exposed to volatile spot and short-term prices and, possibly, the exercise of market power. A $1000/MW DCBC is excessive under these circumstances.

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[23] In its May 15, 2002 "Order on Rehearing and Clarification" in Docket Nos. EL00-95-053, *et al.*, the Commission denied the ISO's request for rehearing of the Commission's determination that marketers seeking to import Energy into the ISO's real-time markets must bid $0/MW and be price takers.

[24] Further, because a substantial portion of the electricity being imported into California is from hydroelectric facilities, California is at the mercy of hydro reserves that vary from year-to-year.

Finally, unlike the eastern ISOs, the ISO currently does not have any mechanism designed to encourage LSEs to forward contract. In that regard, as discussed in Section K. *infra*, each of the eastern ISOs imposes an installed capacity ("ICAP") or similar obligation on LSEs based on LSEs' peak load requirements. The ISO's ACAP proposal will provide incentives for LSEs to forward contract and for generators to construct new power plants to serve California load. However, as discussed above, the ISO does not propose to implement ACAP until January 2004. Until LSEs are able to forward contract, a mechanism is put in place to encourage forward contracting (and the construction of new generation), and California's supply-to-demand imbalance is corrected, there is no basis to implement a $1,000/MWh DCBC as proposed by the generators.

2. There is No Cost Justification for a $1000/MW DCBC

Several suppliers allege that the proposed DCBC will prevent suppliers from recovering their costs and discourage investment in new generation in California. Reliant at 20; Dynegy at 18-19. Suppliers also claim that the DCBC fails to take into account opportunity costs and scarcity rents. Mirant at 19;

The Commission properly should ignore these hyperbolic, "the-sky-is-falling" types of claims. These cost-recovery arguments have been trumpeted by suppliers for the past two years and have been addressed and rejected by the Commission in its price mitigation orders. *See, e.g.,* June 19 Order at 62,560-65. Moreover, the generators do not specify the actual costs they are incurring to operate their plants. It is disingenuous to argue that a higher DCBC is necessary to permit cost recovery without identifying, with specificity, the actual costs that are being incurred. As the Commission has recognized, if suppliers are truly concerned about cost recovery, they are free to file for cost-based rates to be assured that they are compensated for their costs. December 19 Order at 62,204.

In any event, "bilateral contracts should be the principal means by which generators recover their total costs." April 26 Order at 61,364. Accordingly, "generators should be willing to sell any residual real-time energy for any price at or higher than their marginal cost." *Id.* In prior mitigation orders, the Commission sought to provide prices that emulate those that would result in a competitive market (*i.e.* marginal costs) and provide generators with a reasonable opportunity to recover their costs. June 19 Order at 62,563-64. By using the marginal cost of the last unit dispatched to establish the market clearing price, more efficient generators will be reimbursed for more than their marginal costs, *i.e.* they will have an opportunity to recover capital costs and essentially receive scarcity rents (because they will receive the price of the last amount dispatched). April 26 Order at 61,363; June 19 Order at 62,563-64. Because generators such as Duke, Dynegy and Reliant have a portfolio of generating capacity, they will have units that are more efficient than the unit setting the market price. The amounts earned on the more efficient plants will cover the investment in the marginal plant. June 19 Order at 62,563.

In response to claims that marginal cost pricing does not provide sufficient scarcity rents to the highest cost, most marginal units, the Commission has found it unnecessary to include any scarcity adder. December 19 Order at 62,212; April 26 Order at 61,363-64. Finally, objections that the DCBC fails to permit recovery of opportunity costs are flawed because power that is available in real-time does not have any real opportunity to be bid elsewhere, and energy bids from energy limited resources can reflect the opportunity costs from foregoing sales in future periods since the DCBC will apply in future periods as well. April 26 Order at 61,364; June 19 Order at 62,563.

In the ISO's opinion, the DCBC provides protection against market power abuse while allowing for increases in costs. In that regard, the last price ceiling pursuant to the June 19 Order was $92/MWh. At that time, gas prices were approximately 97 percent higher than current prices.[25] If the ISO were to recalculate the price cap, the price would be approximately $45/MWH. See "Motion for Clarification, Request for Rehearing, Petition for Reconsideration and Motion for Expedited Consideration, Docket No. EL00-95-058, *et al.*, p. 9(June 7, 2002). Thus, a $108/MWh DCBC appears to be more than adequate. Further, as discussed above, real time prices in the ISO's imbalance Energy market have been well below $108/MWh since implementation of the west-wide mitigation. This further suggests that a $108/MWh cap is not unreasonable.[26] According to the California Energy Commission's 2002-2012 Energy Outlook Report (February 2002), the annual fixed cost revenue requirements for a new combined cycle

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[25] The proxy figure for gas costs for April 2002 is $3.37 MMBtu. The proxy costs figure for natural gas costs establishes the $108/MWh mitigated price is $6.64/MMBtu

[26] During peak hours, the ISO real time Energy prices generally reflect the marginal cost of very old, inefficient thermal generation units. Thus, the real time prices provide sufficient profit margins to attract investment in new generation.

generation unit range from $85/KW/year to $100/MW/year. A$108/MWh price cap provides an opportunity to earn revenues well in excess of this range. [27]

D. If the Commission Does Not Extend the West-Wide Mitigation, The Commission Should Approve the AMP Mechanism in Conjunction With the Proposed DCBC

1. AMP and a DCBC Are Not Redundant

During the stakeholder process, several parties contended that it was not necessary to have both a DCBC and an AMP mechanism. The DCBC and AMP are complementary tools for the mitigation of economic withholding. They are not redundant.[28] The DCBC limits the magnitude of price spikes; whereas AMP limits the frequency of price spikes. In that regard, the DCBC sets a limit on the maximum bid price the ISO will accept in its markets. On the other hand, AMP compares bids to reference levels (*i.e.*historical accepted bids adjusted for changes in natural gas prices) to determine if the bids deviate significantly from the reference level and have a significant impact on the market- clearing price. Thus, the DCBC limits the magnitude of a price spike in a given hour. AMP limits the frequency of price spikes by limiting the ability of supplies suddenly to change their bidding patterns in way that cannot be explained by costs.

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[27] Assuming a capacity factor of 80 percent (unit is economic 7,000 hours per year), for a new combined cycle unit in 2003 and an annual fixed cost revenue requirement of $100/KW/year, the resource would only have to earn an average spread between its operating costs and the average wholesale energy price of $14.30/MWh (e.g. $100/KW/year * 1,000MW/KW * 1/7,000 hours/year).

[28] The ISO notes that the NYISO has both AMP and a DCBC in place. Thus, the Commission appropriately does not view these two price mitigation tools as redundant.

2. The Commission Should Reject the General Arguments Against AMP

Certain suppliers raise generic objections to AMP. These objections include the following: (1) AMP makes new generation and transmission less likely to be built; (2) AMP does not distinguish between competitive conditions and market power; (3) AMP does not allow for sufficient consultation with generators; and (4) AMP should be applied on a regional basis.[29] Duke at 15; Williams at 20-21. These and similar general objections were raised with respect to the New York Independent System Operator's (NYISO) AMP proposal. Despite these arguments, the Commission approved the NYISO's AMP proposal on an interim basis by order issued June 28, 2001. *New York Independent System Operator, Inc.*, 95 FERC ¶ 61,471 (2001). On May 1, 2002, the Commission, in Docket No. ER01-3155 issued an " Interim Order Extending Automated Mitigation Procedures And Penalty Procedures" in which the Commission extended the AMP through May 31, 2002. On May 31,2002, the Commission approved AMP as a permanent element of the NYISO's market mitigation scheme. *New York Independent System Operator, Inc*. 99FERC ¶ 61,246 (2002)("AMP Order"). In its AMPOrder, the Commission expressly found that the AMP proposal would not unduly burden the entry of new generation. No intervenor argues that AMP is appropriate for New York but not for California. Under these circumstances, because the Commission had already addressed generic objections to an AMP

[29] Reliant claims that the ISO is basing its proposed bid screens on cost-based proxies not historical bids. Reliant at 21. That is incorrect. The MD02 Filing clearly states that the ISO is using accepted bids as reference levels. MD02 Filing, Attachment A at 137-40.

mechanism --- and dismissed such arguments --- the generic arguments against AMP raised herein cannot serve as a basis for rejecting the ISO's AMP proposal.

The ISO believes that it is important to stress a couple of points. First, the ISO's AMP proposal provides for consultation with generators in order to prevent unwarranted mitigation of bids in instances where there are legitimate reasons underlying bids that otherwise appear to be inconsistent with competition. *See* proposed Original Sheet No. 508H, Section 3.3.

Second, AMP will not exacerbate "seams" issues, and it is not necessary to design AMP on a regional basis. The ISO realizes that applying AMP to import bids may deter import participation in the ISO markets, but fundamentally if market power is to be effectively mitigated, it must be applied to all participants. Otherwise, suppliers will attempt to circumvent the mitigation through trades with unmitigated parties. If the Enron Memos and subsequent responses from other market traders have shown us anything, it is that there is no limit to the extent to which traders will collaborate to make profits. By applying AMP to imports (which are an important component of the California market), the ISO is merely according equal treatment to all sellers of electricity in California.[30]

Finally, under the AMP proposal, to the extent multiple resources have submitted bids that exceed the respective bid thresholds, they will be mitigated simultaneously to determine if they have a material impact on market-clearing

[30] Certain intervenors note that the NYISO's AMP does not apply to imports. There are two factors that support the application of AMP to imports in the California market. First, imports are a more integral part of the market in California than in New York. Thus, applying AMP to imports provides for a more equitable and comprehensive mitigation approach. Second, as the Commission has recognized on several occasions, there are significant concerns about "megawatt laundering" in California. June 19 Order at 62,564; December 19 Order at 62,192. Imports should be subject to AMP because of the potential for internal resources to circumvent AMP by engaging in "megawatt laundering."

prices. Mirant claims that this element of the ISO's AMP proposal is inappropriate because it unfairly presumes collusion between market Participants that submit bids. Mirant at 27. This same issue was raised in the NYISO's AMP proceeding,[31] and the Commission did not order the NYISO to remove such provision from its AMP procedures. Consistent with its rulings regarding the NYISO's AMP mechanism, the Commission should not eliminate such provisions from the ISO's proposed AMP. As Dr. David B. Patten, the NYISO's market adviser recognized in his Affidavit attached to the NYISO's AMP Answer, "in a repeated market with the same supplies, economic theory suggests that when a market is highly concentrated or otherwise subject to market power abuse, bids of oligopoly supplies will account for the bids of other suppliers." Although this does not constitute explicit collusion, it does justify the joint assessment of market impacts that is contemplated under the AMP.

3. The Commission Should Not Require the ISO to Adopt the Conduct and Market Mitigation Thresholds That Trigger Mitigation Under the NYISO's AMP

Under the ISO's AMP proposal, the threshold for measuring a given resource's bid is the lower of a 100 percent increase or an increase of $50/MWh for that resource's reference level. The market impact threshold would be equal to the lower of a 100 percent increase or an increase of $50/MWh in projected real-time market clearing prices. Several intervenors claim that the ISO has not justified using thresholds that are lower than the AMP thresholds employed by the NYISO. Mirant at 23-25; Duke at 15; Reliant at 22. In that regard, the bid

[31] *See* Request for Leave to Reply and Reply of the New York Independent System Operator, Inc. to Comments and Protests, Docket No. ER01-2076, pp.9-10 (June 8, 2001) ("NYISO AMP Answer.")

threshold used by the NYISO is an increase of 300 percent from the reference level or $100/MWh, whichever is lower. The market impact threshold used by the NYISO is whether the bidding behavior resulted in an increase of 200 percent or $100/MWh, whichever is lower.

The thresholds developed by the NYISO are not appropriate for the California market. The NYISO's more generous bid and market impact thresholds may be appropriate for markets that are workably competitive most of the time. However, such thresholds are too large to provide effective mitigation in the California market that is significantly less competitive. The NYISO's 2000 Annual Report (p. 12) states that "the markets, except for isolated instances operated competitively and electricity prices during 2000 were not unreasonably high." The NYISO's Market Advisor, Dr. David D. Patton, in his Annual Assessment of the New York Electric Markets 2000, as presented to the joint Board of Directors and Management Committee meeting of April 17, 2000 stated that "markets have been competitive in most conditions." Mr. Patton's statements were brought to the Commission's attention in Docket No. ER01-2076, *i.e.*, the proceeding in which the Commission initially accepted the NYISO's AMP proposal. *See* Request for Leave to Reply and Reply of the New York Independent System Operator, Inc. to Comments and Protests, Docket No. ER01-2076, pp. 2-3 (June 8, 2001). Thus, the Commission approved the NYISO's AMP thresholds with the understanding that the NYISO's markets were generally competitive.

Workable competition does not yet exist in California and there is no evidence in this proceeding to suggest otherwise. Indeed, no party that has intervened in the instant proceedings—including the generators who oppose the west-wide mitigation, AMP, the proposed DCBC and the 12-month market competitiveness index--claims that a workably competitive market exists in California or have provided objective evidence that the events of 2000-2001 cannot be repeated. Accordingly, there is no basis for the Commission to impose the NYISO thresholds that were adopted in an environment of more robust competition. The same arguments raised above (and in the MD02 Filing) to support continuation of the west-wide mitigation and a lower DCBC (than NYISO, PJM and NE ISO) also support lower AMP thresholds than those employed in New York. There is no need to repeat those arguments again.[32]

In any event, the ISO submits that its proposed thresholds are fairly generous. Specifically, the ISO essentially allows suppliers to double their bids (under comparable conditions). Moreover, the AMP thresholds are indexed to natural gas prices, so suppliers are adequately protected if natural gas prices rise. Finally, AMP will not be applied during hours when the ISO forecasts loads in excess of 40,000 MW. This will help ensure that sufficient supplies are bid into the ISO real-time market during potential hours of scarcity, thereby creating the opportunity for the collection of scarcity rents. Finally, as the ISO has made clear

[32] In California, the Commission has expressly found prices to be unjust and unreasonable and the market structure to be seriously flawed. The Commission currently is conducting an investigation of manipulation in California's electricity markets, and the Enron Memos show that extensive "gaming" and/or market manipulation has occurred in California. None of these conditions exist in the New York market.

in its MD02 Filing, as market conditions improve, the ISO will seek to relax the thresholds.

Some intervenors argue that the Commission should require the ISO to revise its AMP proposal to apply only to the day-ahead energy market because the NYISO's AMP only automatically mitigates bids in the day-ahead market. Mirant at 29. Mirant also argues that automatic mitigation is not needed in the real-time market "because buyers in California are by now aware of the inherent volatility of spot market prices and the need to assemble a supply portfolio based on sound risk management principles to limit their exposure to such volatility." Mirant at 29.

The ISO notes that the NYISO applies market conduct and impact procedures manually in real-time and has authority to mitigate bids prospectively that are found to violate the conduct and impact thresholds. In addition, as discussed in the recent Commission Order approving the NYISO's comprehensive market power mitigation plan, the NYISO intends to implement automatic mitigation procedures for local market power in real time by August 31, 2002. AMP Order at 10. The "substantive" provisions of AMP are applicable to the real-time market in the NYISO. The ISO is merely proposing to apply such procedures automatically in real time. AMP is intended to protect against certain types of anti-competitive bidding behavior. It is ridiculous to think that such anti-competitive bidding behavior can exist only in the day-ahead market but not in the real-time market.

F. A $30/MWh Negative Damage Control Bid Cap is Appropriate

A couple of generators contend that there is no reason to set the decremental bid cap at negative $30/MWh. Mirant at 27; Williams at 22. They claim that a negative $30 cap does not take into account costs they might incur such as gas imbalance and operational flow order charges and unit wear and tear. Mirant at 27. Duke at 16. The generators also claim that the ISO's proposal does not take into account a generator's exposure to replacement energy costs and uninstructed deviation penalties. Specifically, they state that if a unit is scheduled to run at a specific ramp rate in the current hour and at a higher ramp rate the next hour – and the ISO "Decs" the unit – the unit will be unable to ramp up to the scheduled level the next hour, thereby incurring replacement energy costs and uninstructed deviation penalties. Mirant at 22; Williams at 27. Finally, Williams states that if a supplier has already sold ancillary services on a unit, it may be necessary to buy such services back in order to participate in the decremental energy market, and any negative decremental bid cap should allow for recovery of the costs of buying ancillary services. Williams at 22-23.

In the MD02 Filing (Transmittal Letter at 44), the ISO identified the following situations where the ISO potentially could be faced with negative energy bids: (1) imports submitting low "Dec" bids in order to be dispatched as price takers; (2) decremental bids being dispatched in real-time to manage inter-zonal congestion; and (3) system wide over-generation. Negative decremental bids are essentially bids for the ISO to pay a generator not to produce energy that the supplier has sold. In a well-functioning, competitive market, suppliers would compete in the decremental energy market by submitting positive decremental bids that track a generator's avoided costs. Indeed, the Commission has recognized

> [i]n a competitive situation, a generator would set its bid at the level of costs it can avoid by not generating. Because each generator has been paid the market clearing price for its commitment to operate in real-time, each generator would be indifferent to operating and incurring running cost, or not operating and paying the ISO an amount equal to its running cost.

California Independent System Operator Corporation, 90 FERC ¶ 61,006 at 61,012

(2000).

Because the California market is not competitive, a cap on negative "Dec" bids is necessary to mitigate market power in system overgeneration conditions. In such conditions, suppliers in the California market routinely submit negative "Dec" bids that are far in excess of any variable production costs generators incur in connection with "Dec-ing", and there are circumstances where the ISO is forced to accept such bids.[33] The ISO notes that over the past 12 months accepted "Dec" bids generally have been within the proposed cap. *See* Attachment A at 2. However, in late June and early July of 2001, for example, negative "Dec" bids exceeded the cap because the ISO desperately needed decremental energy. This is the type of situation the negative bid cap is intended

[33] The ISO notes that in Docket No. EL02-51 the California EOB filed a complaint against numerous generators alleging that such generators were exercising market power by submitting anticompetitive negative "Dec" bids. The EOB complaint identified instances of suppliers submitting anticompetitive "Dec" bids. The Commission dismissed the EOB complaint without prejudice finding that it was premature to undertake a piecemeal modification to the ISO's market design given that the filing of a revised market design was imminent. *California Independent System Operator Corporation, et al.*, 98 FERC ¶61,327 (2002). The Commission indicated that it "expect[ed] the Cal ISO to address the EOB's concerns in the revised market design."

to address, *i.e.*, when suppliers can exert market power in the decremental energy market. Thus, the ISO's proposal is narrowly tailored so that it will not to intrude on suppliers in times when market power is not being exerted.

The ISO recognizes that there may be legitimate costs associated with "Dec-ing" a unit. Those costs are identified in the MD02 Filing. However, the incurrence of such costs need to be considered in the proper context. In that regard, even though a supplier is "Dec-ing", it has already sold energy and will be compensated by its buyer for the higher level of output even if the ISO reduces the generator's output. In other words, the generator will be paid for energy it does not have to produce. Moreover, if the ISO accepts the supplier's negative "Dec" bid, the ISO will be paying the supplier to reduce its output by the amount of the negative bid. Thus, there is a built-in over- recovery when the ISO accepts a negative "Dec" bid. This is illustrated by a simple example of a generator that has scheduled (and sold) 400 MW for an upcoming hour, and the ISO accepts a negative "Dec" bid for the unit to run at 200 MW for the hour. The generator would be paid by the buyer as if it were running at 400 MW, plus it would be paid the negative "Dec" bid price for 200 MW.   Although the generator might incur costs associated with "Dec-ing," it also must be recognized the generator will no longer incur the incremental costs associated with running at 400 MW. The protests fail to recognize that although suppliers might incur some additional costs to "Dec", they will be avoiding other costs (costs for which they are still being compensated and then some).

Mirant makes general allegations that the proposed negative bid cap does not take into account specific charges it might incur to “Dec”, *i.e.* pipeline imbalance and OFO charges. However, Mirant does not offer any specific examples of costs it has actually incurred in a particular “Dec-ing” situation. The ISO submits that there is no reasonable basis to expect that cost factors can justify a bid below negative $30/MWh – especially in light of the built-in over-recovery discussed above. It is interesting to note that, although Mirant and Williams contend that a $30/MWh cap is insufficient to ensure cost recovery, another generator – Calpine – states that $30/MWh is “adequate.” Calpine at 6.

In any event, the Mirant’s claims about the level of charges they will incur are speculative. It that regard, in recent orders, the Commission has taken actions “to help shippers avoid imbalances and penalties and reduce the need for OFOs.” *Regulation of Short-Term Natural Gas Transportation Services and Regulation of Interstate Natural Gas Transportation Services*, Order No. 637, FERC Stats. & Regs. [Regulations Preambles 1996-2000], ¶ 31,091 at 31,310 (2000), *order on rehearing*, Order No. 637- A, FERC Stats. & Regs. [Regulations Preambles 1996-2000], ¶ 31,099 (2000). For example, in Order No. 587-G , the Commission took the first step toward increasing shippers’ abilities to manage imbalances by requiring every pipeline to (1) allow for shippers to revise nominations during the day (thereby reducing the probability of imbalances) and (2) permit shippers to offset imbalances across contracts and trade imbalances amongst themselves. *Standards for Business Practices of Interstate Natural Gas Pipelines*, Order No. 587-G , FERC Stats. & Regs. [Regulations Preambles

1996-2000], ¶ 31,062 (1998). Mirant also fails to acknowledge that pipelines have (1) cure periods (ranging from three to 45 days) in which shippers can correct imbalances without incurring a penalty, (2) tolerance bands (up to 10 percent) below which no imbalance penalties are assessed, and (3) tiered penalty structures where the penalty level is based on the quantity and duration of the imbalance. *See, e.g.*, *PG & E Gas Transmission, Northwest Corporation*, 98 FERC ¶ 61,365 (2002). Under these circumstances, generators are likely to incur minimal, if any, imbalance penalties as a result of "Dec-ing".

With respect to generators' incurrence of OFO penalties, the ISO notes that in Order No. 637 the Commission revised its Regulations to establish a policy that pipelines must adopt procedures to "minimize" the use of OFOs and the adverse affects of OFOs on shippers, as well as identify clear pipeline specific standards based on operational conditions as to when OFOs will be implemented. Order No. 637 at 31, 312-13. Moreover, the Commission made it clear that OFOs should be imposed only to protect **system** integrity and reliability. Order No. 637-A at 31,604. Mirant fails to show how "Dec-ing" will threaten operational integrity and reliability (or otherwise result in a system emergency) on a large pipeline. In other words, it is not reasonable to expect that generators will be incurring OFO penalties as a result of "Dec-ing".

The specific examples provided by Mirant and Williams do not serve as a legitimate basis to increase the cap on negative "Dec" bids.[34] Under the MD02

[34] Williams' example regarding the buyback of ancillary services in order to participate in the decremental energy market appears to be nothing more than an attempt to play the " Dec game" and cover their risk in doing so. Williams would essentially be loading up a unit and submitting "Dec" bids. The Commission should not countenance this type of behavior.

proposed real time Economic Dispatch, real time dispatches will reflect ramp rate limitations. As long as a generator is following its hour-ahead schedule, as modified by ISO dispatch instructions (incremental or decremental), it will not be subject to an uninstructed deviation penalty.

G. No Arguments Raised by Intervenors Warrant Rejection of the 12-Month Market Competitiveness Index[35]

1. The Federal Power Act Does Not Preclude the ISO From Imposing Mitigation Measures

Several generators contend that the Commission must reject the ISO's proposed 12-Month Market Competitiveness Index ("12-Month MCI") because it is inappropriate to permit the ISO to impose mitigation. Williams as 22; Mirant at 15. Williams contends erroneously that such authority is entrusted solely with the Commission under the FPA. Williams at 22.

These arguments lack any legal basis. The Commission has granted every other ISO authority to impose mitigation upon the triggering of specified thresholds or identification of specified impermissible bidding behavior. *See*, *e.g.*, *PJM Interconnection, L.L.C.*, 96 FERC ¶ 61,233 (2001); *ISO New England, Inc.*, 95 FERC ¶ 61,125 (2001); *New York Independent System Operator, Inc., et al.*, 90 FERC ¶ 61,317 (2000). In fact, the Commission has expressly rejected arguments that ISOs should not have authority to mitigate without specific Commission approval on a case-by-case basis. 90 FERC at 62,054. The Commission has noted that the "ability to mitigate when specific thresholds are triggered will help to remedy market power quickly and deter participants from

[35] In Attachment B hereto, the ISO addresses the comments of certain intervenors regarding the 12-month MCI proposal.

exercising market power. *Id.* at 62,054-55. Accordingly, the Commission cannot reject the 12-month MCI on the grounds that it is impermissible for an ISO to impose mitigation.

The important issue is whether the 12-month MCI is just and reasonable and establishes specific thresholds and a bright line test. *Id.* at 62,052. For the reasons set forth herein and in the MD02 Filing, the ISO submits that the 12-month MCI satisfies these criteria and should be approved by the Commission.

2. The 12-Month MCI Permits More than Adequate Cost Recovery

Williams claims that the 12-month MCI will not allow generators to recover all marginal costs of production and allocated fixed costs. Williams at 21. Mirant argues that the 12-month MCI ignores legitimate costs such as risk premiums, opportunity costs and scarcity rents. Mirant at 17. Mirant claims that the ISO's proposal – which bases the competitive baseline average costs on the marginal costs of the highest cost unit available to serve load – rests on the erroneous assumption that prices in a competitive market should be at or near short-run marginal costs. *Id.* Reliant states that the 12-month MCI fails to account for factors that influence prices such as imports and the highest cost units. Reliant at 18.

The ISO submits that the intervenors' arguments are based on misperceptions of the ISO's proposal, faulty economic reasoning and logic that is directly at odds with prior Commission decisions. The Commission Staff's Strawman Discussion Paper (p. 2) for the market power mitigation panel at the technical conference on February 5-7, 2000 in Docket No. RM01-12 recognizes “[c]ompetitive prices are high enough to recover marginal costs of production. In the short run, competitive prices are set by short-run marginal cost.” Similarly, the D.C. Circuit has recognized that “[I]n a competitive market, where neither buyer nor seller has significant market power, it is rational to assume that the terms of their voluntary exchange are reasonable, and specifically to infer that price is close to marginal costs, such that the seller makes only a normal return on its investment. *Tejas Power Corporation v. FERC*, 908 F.2d. 998, 1004 (D.C. Cir. 1999). The 12-month MCI would measure prices in the day-ahead, hour-ahead and real time markets, *i.e.*, in “short-term” markets. Accordingly, it is appropriate that the 12-month MCI measure short-run marginal costs.[36]

With respect to the cost recovery arguments raised by intervenors, such arguments ignore the fundamental policy enunciated by the Commission in prior orders that fixed costs should be recovered in bilateral contracts. April 26 Order at 61,364. Similarly, the arguments regarding the recovery of (or inability to recover) opportunity costs and scarcity rents ignore several important facts. First, market-clearing prices are set by the most expensive unit needed to meet demand. Because most generation resources have lower costs than the marginal unit being dispatched, such units will essentially be recovering capital and opportunity costs[37] and scarcity rents. April 26 Order at 61,363; June 19 Order at 62,563-64. Second, the 12-month MCI allows a $5/MWh markup above

[36] For the competitive baseline, the 12-month MCI utilizes the variable operating costs of the marginal (*i.e.* highest cost) thermal generation unit. Under these circumstances, it is difficult to fathom how Williams can reasonably claim that the 12-month MCI will not allow recovery of marginal costs.

[37] Again, it must be noted that units scheduled in real time do not have a real opportunity to bid elsewhere. As such, arguments that prices in real time need to account for opportunity costs are flawed. April 26 Order at 61,364; December 19 , Order at 62,212.

the highest marginal cost unit.[38] This will more than enable generators to recover fixed costs, opportunity costs and scarcity rents, thereby making the total return allowed very generous. Third, the 12-month MCI expressly takes into account opportunity costs for certain energy limited resources. *See* Original Sheet No.298B, Section 2.8.2.1.3 (2). Fourth, the 12-Month MCI expressly account for scarcity. *See* Original Sheet No. 298D, Section 2.8.2.1.5. Thus, to the extent suppliers collect scarcity rents during periods of true scarcity, the 12-month MCI will not use such scarcity rents as a basis to trigger mitigation. Fifth, the 12-month MCI uses daily spot market prices in determining marginal costs.

Finally the ISO notes that for the period April 1998-March 2000, the price-cost markup in California's energy markets was significantly under the $5/MWh markup included in the 12-month MCI.[39] See MD02 Filing, Affidavit of Anjali Sheffrin at 9. No supplier has contended that prices during that period were insufficient to permit cost recovery, and the $5/MWh markup proposed by the ISO would allow significantly more cost recovery than occurred during that two-year period. Further, as shown in the Affidavit of Anjali Sheffrin (pp. 9-10), prices during that two-year period did not deter suppliers from proposing to construct new generation in California.

[38] Thus, Reliant's claim that the 12-month MCI fails to account for the highest cost units is misplaced.

[39] Specifically, from April 1998-March 1999, the price-cost markup averaged - $0.84 and for the period April 1999-March 2000, the price-cost markup averaged $2.29. MD02 Filing, Affidavit of Anjail Sheffrin at 9.

3. The 12-Month MCI is a Useful Tool to Measure Market Competitiveness

Mirant claims that the 12-month MCI has absolutely no value in determining whether the market is competitive or whether market power has been exercised. Mirantat 16. Duke contends that the 12-month MCI will result in price mitigation even when prices are not the product of market power. Duke at 16. Interestingly, no party provides specific examples of how the 12-month MCI fails to evaluate market competitiveness or will result in improper price mitigation.

These intervenors' opinions are contrary to the opinion of the ISO's Market Surveillance Committee (MSC) which "strongly endorse[s] the concept of a rolling 12-month competitiveness index." MD02 Filing, Appendix V, Comments of the Market Surveillance Committee of the California ISO on the Proposed October 1, 2002 Market Power Mitigation Measures, p. 7. The MSC noted that the 12-month MCI is "designed to provide a high level, longer-term evaluation of the overall competitiveness of the market." *Id.*at 6. The MSC also indicated that "[s]uch a long-term measure can also be a very useful diagnostic tool" and "[a]n annual measure can overcome many of [the] shortcomings" that make short-term measures of market performance unreliable. *Id.*

Moreover, the 12-month MCI addresses the considerations identified in the Commission Staff's Strawman Discussion Paper. In that regard, the Strawman Discussion Paper defines market power as the "ability to raise market price above the competitive level" and "[f]or a price to be above the competitive level, the price must reflect an excess over true scarcity value." Strawman Discussion Paper at 1. Further, the Strawman Discussion Paper (p. 2) states “[co]mpetitive prices are high enough to recover marginal costs of production. In the short run, competitive prices are set by short-run marginal costs.” The Strawman Discussion Paper also outlines the characteristics of just and reasonable rates and the standards for significant and sustained market power:

> Competitive prices reflecting no market power should be considered just and reasonable. The Commission should intervene in markets, beyond standard preventative measures, when market power is significant and sustained….
>
> Significant market power involves prices some significant degree above competitive levels. Sustained market power includes circumstances which cannot be remedied by short-term supply, demand or market rules. Probably it should be measured in months, rather than hours or years. Sustained market power includes recurring market power that may appear and disappear with cyclical demand variation. Investment and entry of generation or transmission, given significant construction and siting timelines, typically takes too long to prevent significant and sustained exercises of market power. The Commission may wish to develop more specific standards of significant and sustained market power. For example, the Commission may wish to adopt a standard that balances the trade off between the magnitude and the length of time of the price increase.

Strawman Discussion Paper at 2-3.

The 12-month MCI addresses the aforementioned considerations. Specifically, it measures significant and sustained deviations of market prices above competitive levels, balances the magnitude at the price spike with the length of time the increased price was charged and considers scarcity rents. Mitigation measures would not be invoked due to occasional price spikes if the overall market remains competitive.[40] Affidavit of Anjali Sheffrin at 13.

[40] For example a moderate markup slightly above $5/MWh during every month of a 12-month period will trigger mitigation, as will an extreme sustained mark-up of $30/MWh for a two-month filing. MD02 Filing, Appendix A at 142-43.

The Commission has defined market power as a seller's ability to "significantly influence price in the market by withholding service and excluding competitors for a significant period of time. *Citizens Power & Light Corporation*, 98 FERC ¶ 61,210 at 61,777 (1989). In *Alternatives to Traditional Cost of Service Ratemaking for Natural Gas Pipelines*, 74 FERC ¶ 61,076 at 61,232 (1996), the Commission concluded that "if a company can sustain an increase in its rates in the order of 10 percent or more without losing significant market share, the company is in a position to exercise market power to the detriment of the public interest. The proposed 12-month MCI is a comparable mechanism except that it utilizes a fixed threshold of $5/MWh above competitive costs rather than a percent mark-up.[41] Just as the Commission's 10-percent price increase threshold is capable of identifying exercises of market power, so is the ISO's $5/MWh price markup threshold.

Under these circumstances, the Commission should adopt the 12-month MCI as a test for determining when market prices are uncompetitive and require intervention to reestablish just and reasonable rates. The ISO recognizes that the 12-month MCI has not heretofore been utilized. Recognizing that the Commission might have reservations about using such a mechanism as permanent tool, the Commission should, at a minimum, consider implementing the 12-month MCI on a trial basis to evaluate such mechanism.

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[41] The MSC has indicated that a percent mark-up is likely to be more sensitive to movements in external factors such as gas prices and, thus, will be more likely to trigger a "false positive" result than would a fixed ($/MWh) threshold. MD02 Filing, Attachment V at 7. A fixed threshold also would provide a stronger incentive for firms to reduce their costs than would a percent mark-up. *Id.* Finally, the fixed threshold can be more easily linked to the long-term average costs of new generation, because the nominal level of the percent mark-up would grow as costs increase. *Id.*

H. The ISO's Proposed Locational Market Power Mitigation Measures Are Necessary, As Well As Just and Reasonable

A few parties protest the ISO's proposal to mitigate bids in instances where resources are situated to exercise locational market power.[42] Mirant at 33-36; Duke at 10-11; Calpine at 9; Williams at 19. The crux of these parties' objections is that the ISO's proposal will not allow them an adequate opportunity to recover their costs. As discussed below, these parties are incorrect.

As a threshold matter, it is critical that the Commission realize that it has approved locational market power mitigation measures for every other ISO. *New York Independent System Operator, Inc.*, 99 FERC ¶ 61,246 (2002); *Consolidated Edison Company of New York, Inc.*, 97 FERC ¶ 61,241 (2001); *PJM Interconnection, L.L.C.,* 96 FERC ¶ 61,233 (2001); *New England Power Pool,* 91 FERC ¶ 61,193 (2000); *Atlantic City Electric Company, et al.,* 86 FERC ¶ 61,248 (1999). Only the ISO does not have any general locational market power mitigation measures in place. It would be arbitrary and capricious for the Commission to deny the ISO similar bid mitigation measures in order to address locational market power. Moreover, the Commission's SMD Working Paper expressly recognizes that mechanisms such as bid caps are appropriate to mitigate locational market power. SMD Working Paper at 23. The ISO's proposal

[42] On the other hand, Santa Clara supports cost based mitigation where locational market power exists (Santa Clara at 12) and TANC refers to the ISO's approach as "an improvement over current procedures" (TANC at 14). TANC goes on to state, "The ISO is moving aggressively to improve the current mechanism for intra-zonal congestion management." In addition, CIWG supports the mechanism that the ISO has chosen to mitigate locational market power. CIWG at 13.

is consistent with the SMD Working Paper and the local market power mitigation measures that the Commission has approved for other ISOs.

Moreover, locational market power mitigation measures are necessary. The Commission has recognized on numerous occasions – not just in the SMD Working Paper – that generators needed for local reliability purposes or generators that operate in load pockets with limited transmission capacity to the main transmission grid have locational market power. *See, e.g., PJM Interconnection, L.L.C.,* 96 FERC at 61,936; *AES Southland, Inc., et al.,* 94 FERC ¶ 61, 248 (2001). In his Affidavit submitted with the MD02 Filing (Attachment P), Eric Hildebrandt discusses locational market power problems in California and identifies numerous instances in which resources with locational market power have played the "Inc Game" and the "Dec Game". Although certain generators challenge the specifics of the ISO's proposal, no generator questions the ISO's need for locational market power mitigation measures.[43]

Further the ISO's proposal to mitigate bids to the proxy price is compensatory. The ISO is using the methodology the Commission previously approved as part of its mitigation plan for California. *See* June 19 Order at 62,561-65. In that regard, the Commission found, that during reserve deficiency

[43] Williams claims that "overly restrictive and, at time, inappropriate price mitigation on the wholesale level, as proposed by the ISO, disables real economic price signals." Williams at 19. Unfortunately, constrained locational pockets exist, even in well-developed markets, that enable suppliers to exercise market power. In such instances, bids must be mitigated. Williams goes on to state that any such mitigation measures should be limited to an arbitrary 18-month duration. As previously noted, even in well developed energy markets there will always be situations where, due to localized transmission constraints, certain suppliers will have the ability to exercise market power. Because of this, the ISO believes, consistent with the Commission's SMD Working Paper, that local market power mitigation measures need to be a permanent feature of a deregulated electricity market. While the ISO would like to have a freely functioning, workably competitive energy market in operation more quickly than even Williams' proposed timetable, the duration of the mitigation measures must be determined by the progress of competitive market development and elimination of physical constraints and not by an arbitrary sunset date.

periods (i.e., where the opportunity to exercise market power is the greatest), the ISO should replace each must-offer resource's market bid with a bid that is the product of the unit's incremental heat rate and a proxy amount for natural gas costs, as well as a $6.00/MWh adder for variable operations and maintenance costs. *Id.* The Commission also directed that the market-clearing price for each BEEP Interval during reserve deficiency periods be established by the highest proxy price of each unit dispatched during that interval.

The Commission's approach is both reasoned and reasonable. While generators must bid at a level representing their marginal costs, they may earn a price higher than that. June 19 Order at 62,563. In that regard, the ISO's proposal (MD02 Filing Transmittal Letter at page 25), is for the Scheduling Coordinator for the Generating Unit to be paid (charged) the higher (lower) of its Commission determined proxy price or the BEEP interval Ex Post Price for incremental (decremental) dispatches. Thus, the mitigation plan pricing contains both cost based and market based components and provides for the payment of the "higher of" the two alternatives.[44] The ISO's proposal to pay generators the higher of their proxy bid price or the market- clearing price guarantees that a unit will recover its costs and then some. The Commission has recognized that such mitigation methodology provides more than an adequate opportunity for sellers to

[44] Moreover, generators cannot set a market-clearing price higher than their marginal costs. Just as the Commission's plan does not allow generators to exercise the market power inherent during reserve deficiencies, but does allow generators to earn a higher market clearing price, the ISO's plan similarly does not allow generators to exercise the market power inherent in being the only unit, or one of only a few units, required to operate to ensure the reliability of a portion of the grid, but does allow generators to earn a higher market clearing price.

recover their costs. December 19 Order at 62,200-15; June 19 Order at 62,560-65.

Mirant complains that the ISO's proposal makes no provisions for the recovery of opportunity costs, risk premiums and other fixed costs. It appears that Mirant is seeking authority to earn extraordinary rates of return in markets that are constrained either from a transmission or generation perspective over a longer period. This perspective is exactly why the ISO needs to have locational market power mitigation measures in place. Because units can earn the higher of the real-time market clearing price or their proxy bid, there will be opportunities to earn net revenues to contribute towards fixed costs. As discussed in greater detail in Section C.2., *supra,* the Commission has rejected the specific cost recovery arguments raised by Mirant on numerous occasions. Mirant provides no new or valid reasons why the Commission should retreat from its prior decisions on this issue. Moreover, if the unit is committed by the ISO, the ISO will ensure full recovery of startup and minimum load costs. Further, there will be ample opportunity to earn net revenues in unconstrained hours, which can be applied towards annual fixed revenue requirements.

Mirant further suggests that no cost based proxy formula can possibly work for the entire market. Thus, Mirant suggests that a mitigated bid level should be developed for each individual unit, or since that this is administratively infeasible, that a value-based approach be developed. In arguing for this "value based methodology," Mirant points inappropriately to such an approach currently being considered by ISO-NE and the New England Power Pool. Mirant at 35.

The ISO submits that the proxy price methodology that is working well in the California market should be applied to mitigate locational market power, rather than adopt an approach that is merely under consideration for use in New England. Moreover, the approach adopted by the ISO is consistent with PJM's approach to mitigating local market power.

Duke supports the concept of limiting prices for generators dispatched to relieve intra-zonal congestion in circumstances where localized market power has been demonstrated to exist. Duke at 10. However, Duke insists on adhering to a market-based approach. In that regard, Duke states that in PJM, a generator may elect to be capped at either a weighted average price the reasonably reflects contemporaneous market conditions for that unit or 110 percent of the unit's operating costs. Again, the ISO's approach permits payment based on the higher of the cost-based proxy approach or the market-based BEEP price as discussed above. Thus, both cost and market elements have been incorporated into the ISO's proposal. With respect to the cost-based component, the ISO is utilizing a methodology previously approved by the Commission for use in California which has significantly different competitive conditions than PJM.

Calpine, citing problems it has had with PG & E with respect to the purported inadequacy of system upgrades that it paid for, argues that "new" generation should not be subject to bid mitigation for locational market power. Calpine evidently believes that new generation is not the same as "old" generation from the standpoint of participating in the "Dec game,"[45] creating

[45] For discussion of the ISO's treatment of "dec game" opportunities, see the affidavit of Eric Hildebrandt, Attachment P to the May 1 MD02 Filing. The affidavit of Eric Hildebrandt affidavit,

congestion in an area and profiting from the decremental revenue from reducing it. New generation can have locational market power just like old generation. It would be unduly discriminatory to exempt new generation from such mitigation measures simply because it is new. Until a full locational marginal pricing regime is put in place, coupled with bidding activity rules that prohibit revising energy bids for capacity selected in prior markets, both old and new generation will be equally able to play the “Dec” game, and cost based mitigation will be required to prevent it.

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I. The Proposed Penalties For Uninstructed Deviations Are Necessary To Ensure Reliable And Efficient Operations, Discourage Physical Withholding And Reduce Opportunities For Gaming

As indicated in the MD02 Filing Transmittal Letter (pp. 34-36) and the Affidavit of Tom Siegel (Appendix Q at 3-6), uninstructed deviations are rampant in the ISO Control Area. In his Affidavit, Mr. Siegel indicated that uninstructed deviations have (1) made it difficult for the ISO to operate the control area reliably in a manner consistent with NERC and WECC standards and good utility practices, (2) adversely affected the ISO’s ability to manage inter- and intra-zonal congestion, (3) resulted in an inefficient dispatch of resources, and (4) inappropriately affected prices in the ISO’s Markets. Appendix Q at 7-8. Although most suppliers object to the ISO’s proposal to impose penalties for uninstructed deviations beyond a three percent tolerance band, not one supplier

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included as Attachment P to the May 1 MD02 Filing, demonstrates with ample examples the need for a cap on both incremental and decremental bids in the ISO market.

disputes the facts identified above and discussed in greater detailed in Mr. Siegel's Affidavit. Instead, the suppliers object to the imposition of penalties and/or argue for a ridiculously high tolerance band (that is contrary to the tolerance bands in place in other ISOs and Commission pronouncements on the issue). The Commission should not countenance these objections because they are contrary to the undisputed facts presented herein.

1. Specific Objections To The Proposed Penalty For Positive Uninstructed Deviations Are Without Merit.

The ISO proposes a penalty for positive uninstructed deviations equal to the quantity of Uninstructed Imbalance Energy in excess of the tolerance band multiplied by a price equal to 100 percent of the applicable BEEP Interval Ex Post Price. Essentially, suppliers would not be paid for energy in excess of the tolerance band. The Cogeneration Association of California ("CAC") argues that it is confiscatory for the ISO to accept energy on the grid and not pay for it. CAC at 4. CAC states that, although the ISO may not have requested the energy, the energy is being consumed and, as such, the generator should be compensated. *Id.*

CAC's argument is absurd, because the ISO has no way to refuse to accept, and the power system has no way to avoid consuming or otherwise having to dispose of, excess energy a supplier has delivered. In fact, the ISO's proposed "penalty" for excess Imbalance Energy is not really a penalty at all, but is a fundamental business principle. A supplier cannot deliver a commodity in an arbitrary quantity beyond what the buyer has ordered, and then require the buyer to accept and pay for it. The fact that the buyer has no way to refuse delivery of the commodity, as in the case of real-time electricity, is hardly a reason to ignore this principle, particularly given the tolerance band that allows for imprecision in the resource operator's control of the resource's output.

The ISO's proposed penalty for positive uninstructed deviations is identical to the penalty that the Commission has approved for the NYISO. *Central Hudson Gas & Electric Cogeneration, et al.*, 86 FERC ¶ 61,061 at 61,266 (1999). There is no rational basis for the Commission to approve such penalty for the NYISO but not for the ISO. As the NYISO's member systems argued in seeking Commission approval for a penalty for positive instructed deviations "overgeneration can seriously affect reliability and cause damage to other generation and transmission equipment." *Id.* In approving the NYISO's proposal not to pay generators for power delivered in excess of the scheduled and requested amount, the Commission stated "[w]e agree… that strong rate disincentives are needed to induce generators to be vigilant in avoiding over-generation and shall accept this proposal. *Id.* Market participants should not be required to pay for energy services the ISO did not request and does not need. CAC's proposal would encourage overgeneration because generators would know they would be paid for such overgeneration. The ISO notes that in 2002 there has been a significant tendency for resources to over-deliver, and this has caused operational problems for ISO dispatchers. This makes it all the more imperative that the Commission approve the ISO's proposed penalty for positive uninstructed deviations.

2. Regardless Of The Fact That The ISO Has Proposed A New Market Design, The ISO Needs Penalties For Uninstructed Deviations Now

Sempra Energy (Sempra) agrees that if generators are not following ISO dispatch instructions to a degree sufficient to provide reliable grid operations, then the ISO "is right to seek a high level of generation compliance with dispatch instructions." Sempra at 7. However, Sempra suggests that the new MD02 market design should fix the problem without the need for penalties. *Id.* Sempra also opines that it is unlikely the Commission will find it necessary to include these types of penalties in its standard market design. *Id.* Finally, both Sempra and Reliant note that PJM does not have penalties for uninstructed deviations and suggest that the financial incentives in a properly designed market are sufficient. Reliant at 23; Sempra at 7.

Even assuming *arguendo* that the new MD02 market design will "fix" the problems resulting from generators uninstructed deviations, Sempra ignores the fact nodal pricing will not be fully implemented until fall 2003. Unfortunately, the problem with uninstructed deviations exists now (and no intervener disputes this fact) and, as such, needs to be fixed now before the ISO faces increased operational problems and "gaming". Sempra's claim that the standardized market designed likely will not impose penalties for uninstructed deviations is at odds with the Commission's "Working Paper on Standardized Transmissions Service and Wholesale Electric Market Design" (SMD Working Paper). The SMD Working Paper (p. 18) expressly contemplates the possibility of "special rules" and "penalties" to deal with uninstructed deviations.

Further, the fact that PJM network service does not have penalties for uninstructed deviations does not mean that the ISO should not have such penalties in place. Indeed, both the NYISO and ISO New England have locational marginal pricing – just like PJM – yet both of them also have penalties for uninstructed deviations. *See* MD02 Filing, Attachment A at 148; *see also* *New York Independent System Operator, Inc.,* 96 FERC ¶ 61, 249 (2001). This fact suggests that a properly designed market, in and of itself does not obviate the need for uninstructed deviation penalties.[46]

Sempra and Reliant also ignore some important distinctions between the ISO and PJM. PJM has a more favorable reserve margin than the ISO. Moreover, PJM arose out of a tight power pool that had been in existence for several decades. That tradition of cooperation and reserve-sharing has carried over today. Further, unlike the ISO, in PJM there is a significant amount of

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[46] Sempra indicates that an ISO conference call regarding the implementation of 10-minute dispatch and settlement suggested that problems associated with uninstructed deviations have diminished as a result thereof. Sempra at 8. Sempra is correct that 10-minute markets have resulted in diminished uninstructed deviations. However, Sempra's comments are irrelevant for purposes of evaluating the ISO's proposal because 10-minute markets were approved by the Commission effective July 1, 2000, and the prevalence of uninstructed deviations (and the problems caused by such uninstructed deviations) discussed in Mr. Siegel's affidavit all are within the 2001-2002 timeframe , *i.e*. **after 10-minute markets were implemented**. . *See* *California Independent System Operator Corporation*, 91 FERC ¶61,324 (2000). Thus, the problem of uninstructed deviations has not been eliminated by 10-minute markets and the ISO is not relying on data from the pre-10 minute market timeframe to support its position. Uninstructed deviations are a major problem now, and they need to be corrected. Further, the conference call discussion regarding uninstructed deviations was based on the ISO's calculation of uninstructed deviations under the **current** settlement process. As indicated in Mr. Siegel's affidavit, the ISO currently pays Instructed Imbalance Energy on an as-delivered basis, so failure to deliver Instructed Imbalance Energy is not settled as an uninstructed deviation. The current process only produces an uninstructed deviation if the actual metered generation exceeds the total Scheduled, plus instructed energy, or is less than the Scheduled Energy. In other words, it does not take into account declined dispatch instructions and deliveries below dispatch instructions that will be considered uninstructed deviations under the MD02 proposal. When these types of uninstructed deviations are considered, the problem is much more significant. Attachment C hereto shows the extent of uninstructed deviations during the time period 10-minute markets have been in effect. As this chart indicates, uninstructed deviations are prevalent in the ISO Control Area.

utility-divested generation that remains under contract to supply the former utility owner, in addition to utility-owned generation. Under these circumstances, there is significantly less incentive for resources to deviate from schedules and PJM dispatch instructions.[47] Further, anticompetitive behavior is less likely to exist in a market such as PJM where there is an excess amount of installed capacity and generation is concentrated in the control of entities in such a way they are not inclined to engage in physical withholding. Finally, if the implementation of the LMP design does completely solve the problem, as Reliant and Sempra assert, then suppliers will consistently follow their final hour-ahead schedules and ISO dispatch instructions to the best of their ability. Under these circumstances, the proposed penalties will not be invoked and no harm will be done by having the penalties in effect.

3. The ISO's Proposal Already Accommodates The "Operational" Concerns Raised By Generators

Several suppliers state that the ISO's proposal must be "modified" to allow Scheduling Coordinators with a portfolio of generators to manage their deviations on a portfolio basis. Calpine at 11; Williams at 25; Duke at 18; Reliant at 24. Certain suppliers also caution that any authorization to impose penalties must accommodate the physical limitations of a generation unit. Williams at 25; Reliant at 23. Finally, Mirant provides two examples that it contends – albeit erroneously—serve as examples of the ISO erroneously sending dispatch

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[47] PJM does impose penalties on point-to-point schedules that deviate beyond a 1.5 percent tolerance band. In addition, in PJM, a resource that deviates from dispatch instructions beyond the tolerance band cannot set the marginal clearing price and must be a price taker. *See* Schedule 1 of the PJM Operating Agreement, Section 2.4; *see also* MD02 Filing, Attachment A at 148. Thus, even PJM penalizes uninstructed deviations to a certain extent.

instructions. Mirant at 44-45. However, Mirant acknowledges that in the two examples the generator would not incur an uninstructed deviation penalty under the ISO's proposal.

It appears that in their cursory review of the MD02 filing, the generators failed to realize that the ISO's proposal already accommodates the portfolio netting they request. Transmittal Letter at 37; Attachment A at 147; Attachment I , Tariff Section 11.2.4.2 (h). The ISO's proposal permits Scheduling Coordinators to aggregate generation units at a single node (and with the same voltage level) for purposes of determination of the Uninstructed Deviation. In addition, the ISO will allow, on a case-by-case basis, other levels of aggregation based on an ISO review of the impact of such netting on the ISO-controlled grid. Market participants proposing unit aggregations will be required to demonstrate that the units aggregated are interchangeable, capable of functioning essentially as a single entity and will not affect grid reliability. MD02 Filing, Attachment A at 147. Thus, the generators' protests are without merit because the ISO has proposed a means of portfolio aggregation.

Moreover, the ISO's proposal accommodates the physical limitations of generating units. However, the ISO cannot stress enough that it is incumbent on generators to submit accurate ramping and operational (and related) information to the ISO and inter-hour schedule changes that are feasible. The ISO should not be required to second-guess bids submitted by a Scheduling Coordinator or scramble to ensure reliable operations because generators have not submitted accurate, up-to-date information regarding the physical capabilities of their units.

At the technical conference in San Francisco on May 9-10, 2002, the ISO made the Commission Staff aware of the problems caused by Scheduling Coordinators submitting inter-hour schedule changes that are not feasible (due to ramping or other technical constraints or otherwise)

Mirant identifies two examples which it claims are indicative of problems with the ISO's EMS which need to be resolved prior to implementation of any penalty mechanism. Mirant at 44-45. Interestingly, Mirant goes on to state that these two examples would not subject Mirant to penalties under the ISO's proposal. *Id.* at 45. It is noteworthy that Mirant does not identify any instances where purported "problems" with the EMS might cause Mirant to incur penalties under the ISO's proposal. The ISO's software incorporates and relies on the data provided to the ISO by generators. If the ISO is issuing dispatch instructions, it is based on information provided to the ISO by generators. The ISO cannot be faulted if that information is inaccurate or the generator cannot perform in a manner consistent with its schedules and bids. This highlights the need for the ISO to receive accurate information and schedules that are feasible.

In any event the ISO provides the following comments with respect to the two examples provided by Mirant. In the first example, Mirant has scheduled their Contra Costa 6 unit in a manner that is inconsistent with its ability to provide Regulation. The ISO does not control Mirant's scheduling practices. Tariff Section 2.5.12 describes the ISO's authority in evaluating bids in the Ancillary Services auctions as:

(a) the ISO shall not differentiate between bidders other than through price and capability to provide the service, and the required locational mix of services:

(b) to minimize the costs of using the ISO Controlled Grid, the ISO shall select the bids with the lowest bids for capacity which meet the technical requirements, including location and operating capability; and

(c) the Day-Ahead Market, the Day-Ahead bids shall be evaluated independently for each of the 24 settlement Periods of the Following Trading Day.

Since each hour is independent of the other, Mirant's Contra Costa 6 is capable of providing the service, the ISO must award the service Mirant if its bid meets the locational needs of the ISO and minimizes the auction price**.** Because the ISO is prohibited from taking hour-to-hour energy schedule changes into account when evaluating Mirant's bid, it is Mirant's responsibility to ensure that they schedule in a manner consistent with their ability to provide the service. Failure to do so may result in loss of all or part of its capacity payment In any event, because there would not be any uninstructed deviation penalty applicable in this example, the example is not relevant to the ISO's uninstructed deviation penalty proposal.

With respect to the second example presented by Mirant, the ISO is only able to dispatch generators based on bids submitted by the Scheduling Coordinator or by proxy bids inserted by the ISO on their behalf when they have not submitted Supplemental Energy bids for their available capacity. The ISO will only insert proxy bids up to the upper limit of Contra Costa 6 unit's regulating range (315 MW). To the extent that Mirant may have submitted Supplemental Energy for their available capacity above 315 MW, the ISO may issue dispatch instructions directing the Contra Costa 6 unit to generate at a level above the upper limit of the unit's regulating range. In this instance, Mirant would have to remove the unit from direct ISO control (AGC) to comply with the dispatch instruction and may be exposed to uninstructed deviation penalties unless they take the unit off AGC. The problem identified here is a problem associated with Mirant's bidding strategies.[48]

4. If The Commission Is Inclined To Approve A Sliding-Scale for Uninstructed Deviations It should Not Approve the Sliding-Scales Proposed By Reliant or Mirant.

Reliant submits that, to accommodate "operational realities," the tolerance band should be expanded to the greater of 5 MW or 10 percent of a unit's maximum operating output. Reliant at 23. Mirant proposes a sliding scale of tolerance bandwidths and penalties. The tolerance band width proposed by Mirant would be 5-10 percent, 10-20 percent and above 30 percent. Mirant 45-46.

Reliant's and Mirant's requests need to be evaluated in the proper context. Other ISOs have tolerance bands for uninstructed deviations ranging from 1.5 percent for ERCOT to 3.0 percent for the NYISO.[49] No Commission-regulated

[48] Finally, the ISO note that it is developing software that would allow market participants to modify their generator availability in real time. Thus, when a generator has reduced its availability, such reduction will be incorporated into the instructions the ISO issues and accounted for in the assessment of penalties for uninstructed deviations.

[49] A table showing the tolerance bands and penalties for other ISO's is set forth in Attachment A (page 148) of the MD02 filing.

ISO has a sliding scale of tolerance bands and penalties. Although ERCOT employs a sliding scale, ERCOT only has a 1.5 percent tolerance band – half of what the ISO proposing. No generator has indicated that it wants to pay penalties outside of a 1.5 percent tolerance band. In addition, no generator has explained why their units can operate properly within the 1.5 percent to three percent tolerance bands in effect in the other ISOs but not within the ISO's proposed three percent tolerance band which is equal to the highest tolerance band of any ISO that has a tolerance band. Further, in Order No. 888-A, the Commission stated

> [a]generator should be able to deliver its scheduled hourly energy with precision. If we were to allow a generator to deviate from its schedule by 1.5% without penalty, as long as it returned the energy in kind at another time, this would discourage good operating practice.

Order No. 888-A, FERC Stats. & Reg.. [Regulations Preambles 1996-2000], ¶ 31,048 at 30,230 (1997). Reliant's and Mirant's proposals are completely at odds with this precedent and entirely too lenient given the operational problems uninstructed deviations cause and the "gaming" activities associated with uninstructed deviations.

The ISO again stresses that penalties for uninstructed deviations are necessary given the prevalence of uninstructed deviations in the ISO control area. The ISO believes that its proposal is just and reasonable. The ISO's proposal is targeted to deter excessive uninstructed deviations, while permitting a reasonable amount of operational flexibility. The ISO's proposal accommodates uninstructed deviations that result in the normal course of unit operations but are sufficiently stringent to provide incentives for generators to submit bids, follow instructions and maintains expected bid output. MD02 Filing, Attachment Q, Affidavit of Tom Siegel at 16. The bottom line is that the ISO needs penalties to deter uninstructed deviations. **Only if the alternative is no penalties**, **and the Commission believes that a tiered approach is appropriate**, then the ISO offers the following alternative to the proposals of Reliant and Mirant:

- For deviations within a bandwidth of 3-5 percent, the generator would be paid 50 percent of the BEEP Interval Ex Post Price for positive deviations and be charged 120 percent of the BEEP Interval Ex Post Price for negative deviations (*i.e.,* the cost of replacement energy plus 20 percent);

- For deviations within a bandwidth of 5-10 percent, the generator would be paid 25 percent of the BEEP Interval Ex Post Price for positive deviations and be charged 135 percent of the BEEP Interval Ex Post Price for negative deviations; and

- For deviations above 10 percent, the generator would be paid 0 percent of the BEEP Interval Ex Post Price for positive deviations and be charged 150 percent of the BEEP Interval Ex Post Price for negative deviations.

The ISO believes that the proposal set forth in the MD02 filing is more appropriate given the prevalence of uninstructed deviations in the ISO Control Area and given the ISO's accommodation of aggregated resources at the same location, or on a broader level as approved on a case-by-case basis. However, the ISO is willing to accept the aforementioned compromise **solely** as an alternative to Commission rejection of uninstructed deviation penalties. However, the ISO submits that, if the Commission approves a sliding-scale approach, it would be wholly inappropriate to allow any aggregation of generation units beyond the bus level.

5. The Proposed Penalties Are Not Contrary to Commission Precedent

Dynegy claims that penalties during non-emergency hours are contrary to Commission precedent. Dynegy at 30. In support of its position, Dynegy cites to Order No. 637, where the Commission stated that natural gas pipelines should only impose penalties in situations where system reliability is threatened. *Id.*

Given that the Commission has approved uninstructed deviation penalties for ISO New England and the NYISO, and the SMD Working Paper expressly contemplates the possibility of penalties for uninstructed deviations, it is clear that **relevant** Commission precedent with respect to electric utilities does not preclude penalties in non-emergency situations. In any event, Dynegy's reliance on Order No. 637 is misplaced. The operation of an electric grid is significantly different than the operation of a natural gas pipeline. Natural gas can be stored either in storage fields or as linepack. If excessive quantities of natural gas are delivered into the pipeline, equivalent volumes can be delivered into storage. If shippers under-deliver supplies to the pipeline, additional quantities can be withdrawn from storage and delivered to customers. On the other hand, electricity cannot be stored, and electricity demand must be balanced moment by moment. Thus, any surge in generation or under-generation requires the transmission provider to scramble in real time to maintain the operational integrity of the transmission grid. Under these circumstances, it is clear why operational problems are much more prevalent on electric transmission grids than they are on natural gas pipelines.

Dynegy also ignores the important fact that a transmission provider like the ISO also runs a real time electricity market in which prices can be impacted – even manipulated -- by uninstructed deviations. Natural gas pipelines do not run a simultaneous natural gas market. Thus, on a natural gas pipeline, there is less need to implement penalties to address "gaming" and market manipulation. On the other hand, as discussed in greater detail in the affidavit of Tom Siegel, uninstructed deviations have a clear impact on electricity prices in the ISO's markets. Moreover, as the Enron Memos indicate, certain types of uninstructed deviations are simply attempts to "game" the system. Dynegy would like to prevent the ISO from having the necessary enforcement tools to protect system reliability, maintain the sanctity and efficiency of electricity markets and counteract "gaming". The Commission should not deny the ISO these needed tools.

Dynegy's reliance on the Commission's general statements in Order No. 637 regarding pipelines' penalty provisions ignores the actions the Commission has taken in individual pipeline proceedings implementing Order No. 637. Specifically, in individual pipelines' Order No. 637 compliance proceedings, the Commission has permitted pipelines to retain their various scheduling, overrun and imbalance penalty schemes. *See, e.g., PG & E Gas Transmission, Northwest Corporation*, 98 FERC ¶61,365 (2001); *Williston Basin Interstate Pipeline Company*, 98 FERC ¶61,212 (2002). The uninstructed deviation penalties that the ISO is proposing are comparable to scheduling, overrun and imbalance penalties. Consistent with its decisions to permit natural gas pipelines to have penalties to address these types of situations, the Commission should permit the ISO to have uninstructed deviation penalties, especially since such penalties are needed more on an electric transmission grid than they are on an interstate natural gas pipeline.

6. The Commission's Prior Rulings Do Not Preclude Approval Of The Proposed Penalties For Uninstructed Deviations

Dynegy claims that the ISO's proposal is "a replay of a replay of a replay." Dynegy at 28. In that regard, Dynegy states that the Commission rejected the ISO's proposal for uninstructed deviation penalties in Amendment 42. Dynegy also states that the ISO's proposal is inconsistent with the Commission's prior orders directing the ISO to remove its penalty provisions. *See* 97 FERC ¶ 61,293 (2001). Dynegy claims that penalties during non-emergency periods are not justifiable given that the Commission rejected penalties during emergencies.

Dynegy misrepresents the Commission's order on Amendment No.42. In its order on Amendment No. 42, the Commission rejected the ISO's proposal as "premature, and direct[ed] the Cal ISO to address these issues in the impending May 1 , 2002 filing of its comprehensive market redesign proposal." *California Independent System Operator Corporation,* 98 FERC ¶ 61,327 (2002). The ISO's proposal complies with the Commission's directives in the Amendment No. 42 Order. Dynegy's "suggestion" that the Commission rejected such penalty proposal on substantive grounds is disingenuous.

Likewise, the Commission's orders directing the ISO to remove its Amendment No. 33 penalties are inapposite. The Amendment No. 33 penalties and the uninstructed deviation penalties proposed in the MDO2 Filing address entirely different situations. Amendment No. 33 was intended to address emergency conditions in California, including the persistent refusal of generators to submit sufficient bids into the ISO's real time energy market and refusing to operate in response to ISO dispatch instructions even when operating out-of-market. *See* Transmittal Letter filed in Docket No. ER01-607, filed on December 8, 2000; *see also California Independent System Operator Corporation;* 93 FERC ¶ 61,239 (2000). On the other hand, the uninstructed deviation penalties proposed herein are intended to address "gaming" and behavior that adversely affects reliable day-by-day operation of the grid and the efficient operation of the ISO's energy markets. In other words, the Amendment No. 33 penalties were primarily intended to address the situation of generators not bidding into the ISO's markets at all; the MD02 penalties are intended to address the situation where generators bid into the ISO energy markets, but do not follow their schedules or dispatch instructions (by either over- or under- generating). The Commission found that the Amendment No. 33 penalties were no longer necessary given the Commission's approval of the "must-offer" obligation that essentially required generators to bid their available capacity into the ISO's imbalance energy market. 97 FERC ¶ 61,293 at 62,367 (2001). The "must-offer" requirement does not address or discourage the types of behavior that the ISO is seeking to discourage in connection with the proposed penalties for uninstructed deviations. Thus, the Commission's rationale for removing the Amendment No. 33 penalties does not apply to the proposed penalties for uninstructed deviations. In that regard, the inappropriate behavior the ISO has identified in its MD02 filing exists with the "must-offer" obligation in place.

J. The Proposed Residual Unit Commitment Procedure Is Necessary, Reasonable, and Should Be Approved Without Modification

Intervenors have submitted comments and protests concerning various aspects of the proposed Residual Unit Commitment ("RUC") procedure. Many of the protests are based on misunderstandings about the purpose of the RUC procedure. The ISO's proposed RUC procedure is an integral element of the MD02 comprehensive market design, is fully consistent with the implementation of LMP by other ISOs, and is an absolutely necessity for the ISO to perform its core function of reliable grid operation under a market system in which the forward markets are primarily financial rather than physical commitments.

Before responding to the specific comments, it is important to lay out the considerations that led to the ISO's proposed RUC design. When the forward markets are primarily financial rather than physical commitments, the system operator cannot depend on either the submitted ("preferred") or final forward schedules to accurately reflect expected real-time loads and generation levels. Rather, market participants will utilize the forward markets for arbitrage. Such arbitrage enhances market efficiency, provided it does not interfere with reliable operation of the transmission system, and this will be the case if the system operator has effective tools to ensure that adequate capacity will be available in real time and will perform in a predictable fashion. The RUC procedure is one of those tools. It enables the system operator to identify and commit additional supply resources on a day-ahead basis when it determines that the resources scheduled day ahead will not be sufficient to meet the next day's load and reserve requirements.

Once the MD02 design is fully implemented, particularly when the forward energy markets are operating and the ACAP obligation is fully effective, the ISO's RUC procedure will be completely consistent with its counterpart procedures in operation by the PJM and NY ISOs. *See, e.g. Central Hudson Gas and Electric Corporation, et al.*, 86 FERC ¶ 61,062 (1999). In the near term, however, the ISO's RUC procedure must be modified and reinforced in order to achieve its purpose. Specifically, until ACAP is fully effective, the ISO must have a reasonably strong Must Offer provision to ensure that enough supply resources will participate in the RUC procedure. In addition, because the ISO is an import dependent control area and imports are not subject to a "must-offer-to-California" provision, the RUC procedure must provide for and encourage import participation. This is particularly true between now and spring 2003, while there is no day-ahead energy market for import suppliers to bid into.

In summary, the ISO's proposed RUC design strikes a careful balance among the following principles and objectives: (1) ensure that enough capacity will be on-line and available for real time, (2) minimize the ISO's forward purchasing of energy by committing resources at minimum load where feasible; (3) provide a reasonable capacity payment for committed Must Offer resources, until such time as ACAP is effective, and (4) provide a way for imports to offer supplies and be procured on a day-ahead basis to supplement in-state supplies. The ISO believes that its RUC design provides a necessary, effective and reasonable reliability tool, and that it incorporates appropriate modifications associated with each phase of MD02 implementation, so that in the ultimate long-term design the ISO's procurement role in the forward markets is minimized. Therefore, as explained further below, the RUC procedure should be accepted by the Commission without modification.

1. It Is Appropriate to Adopt the RUC Procedure and Support It With an Effective Must-Offer Obligation Until ACAP Is Fully Implemented.

Some intervenors express reservations about the adoption of the RUC process at all, several of them instead preferring the current must-offer obligation regime. The arguments of these intervenors reflect a fundamental misunderstanding of both RUC and Must Offer, and are without merit.

To address the misunderstanding first, the key point is that RUC and Must Offer are not substitutes, they are complementary. RUC is an essential reliability commitment procedure performed by the ISO. By itself, however, RUC contains no provision to compel supply resources to participate in the procedure. Therefore, to be effective, RUC must be supplemented by some kind of participation requirement placed on suppliers, such as Must Offer. In the long-term design, the obligation to participate is derived from ACAP. Until ACAP is fully implemented, it is derived from some variation of the current Must Offer obligation.

CIWG asserts that the ISO should continue to employ the must-offer requirement which it argues is necessary for market mitigation, not onerous to generators, and consistent with a competitive marketplace. CIWG at 6-7. The rationale provided by CIWG in support of the must-offer requirement is fully consistent with the concept behind the RUC procedure, as has been proven in practice by other ISOs. The long-term RUC proposal to commit resources from those identified by load-serving entities to meet their ACAP obligations, rather than on a must-offer basis, is virtually identical to the processes employed in the markets overseen by the eastern ISOs, including PJM and the NYISO. MD02 Filing, Transmittal Letter at 17. Moreover, the RUC procedure is an intrinsic feature of the integrated Market Redesign 2002 proposal and should not be disaggregated from that proposal. The ISO therefore supports the continuation of a must-offer requirement for non-hydro PGA resources.

Reliant expresses concern that the RUC would eliminate any incentive for buyers to procure supply on a forward basis because they could rely on RUC to meet real-time needs. Reliant at 9, 11. The ISO recognized this potential in designing RUC, and therefore proposed the following features to discourage buyers' excessive reliance on the RUC process: (1) the RUC process is cost-based only with respect to startup and minimum load costs; it is market-based with respect to the energy bids. Therefore, if an LSE were to rely on the ISO's RUC process for an excessive amount of its load obligations, it would be taking on significant price risk in the real-time market; and (2) any RUC costs will be borne by buyers who do not schedule in the day-ahead market, thereby increasing the cost of real-time energy even further and providing a strong incentive to procure supply on a forward basis.

2. It Is Reasonable To Remove From the RUC Procedure the Current Waiver Process With Respect to the Must-Offer Obligation.

AES objects to the removal from the RUC process of the waiver process that exists with respect to the must-offer obligation, because "the RUC process eliminates any procedure by which a generator may protect itself from being called upon to fulfill an obligation that it cannot meet" and provides "no formal means" by which a physically constrained generator may "protect itself from an arbitrary ISO order." AES at 5-6. The ISO finds this argument confusing. To begin with, it is important to be clear that the resources in question are the long-start-time (LST) units, which require a day-ahead commitment decision if they are to be available the next day. For these resources, the current must offer waiver procedure and the RUC procedure are essentially two sides of the same coin. Whereas the must offer waiver procedure is based on the principle that all LST resources are committed unless explicitly excused (i.e., granted a waiver), the RUC procedure is based on the principle that all non-self-committed LST resources are excused unless given a commitment instruction in RUC. There is no difference between the two procedures as regards the ability of a generator to "protect itself" as AES asserts. The ISO notes in addition that units that are reported to the ISO as being derated, forced out of service, or that are on approved planned maintenance will not be considered in RUC, so there is no danger of such units being called upon when they simply cannot perform.

Having noted the above equivalences between the RUC and the must offer waiver procedures, the ultimate factor in favor of RUC is the fact that it is a true unit commitment procedure, which utilizes a Transmission Constrained Unit Commitment (TCUC) application. The implication of this fact is that RUC will result in consistently efficient commitment decisions, and can take into account transmission constraints and other resource constraints such as limited energy and emissions.

Calpine asserts that the ISO should clarify that a generating unit's capacity that is committed under a contractual obligation will be exempt from the must-offer requirement, and that once a generating unit submits information concerning its contractual requirements and generating restrictions to the ISO, the resulting maximum operating level will be the maximum number of hours for which the ISO can demand must-offer bids from that generating unit.[50] Calpine at 10-11. SMUD opposes the RUC process to the extent that it allows the ISO to call on municipal or federal units that are necessary for such entities to serve their load requirements. SMUD asserts that the RUC process should be limited to units that do not have prior obligations. SMUD at 14-15. TANC contends that the RUC process should be revised to exempt LSE energy-constrained generation that will be used to meet LSE native or contract load. Without such an exemption, TANC states that an LSE would run the risk, for example, that a

[50] Units under a contractual obligation should be scheduled in the day-ahead market. Capacity already scheduled in the day-ahead market is not considered in RUC.

peaker unit would be called for RUC and therefore not be available during peak hours when it is needed to meet load.[51] TANC at 12.

These intervenors raise issues that more accurately relate to the must offer obligation than to the RUC procedure. As noted above, RUC is simply a reliability procedure which, by itself, does not impose any obligation to participate. Rather, those obligations reside in the must offer and ACAP provisions of MD02. Nevertheless, the concerns raised above with regard to the must offer fail to recognize the parameters of the must offer obligation and acknowledge the Metered Sub-System (MSS) provisions being developed in parallel with MD02. The must offer obligation applies only to "available" generation, *i.e.*, generation that is not already committed; must offer does not impede a supplier from meeting its contractual obligations. In the past year, there have been disagreements about what constitutes "available" generation. Given the experience of the past two years – particularly the frequency of tight supply conditions and associated high prices – an effective must offer obligation must address and prevent the exercise of market power through withholding of supply from the market. Therefore, a resource that claims to be unavailable due to a contractual commitment should appear scheduled on a day-ahead basis. To the extent that resource has unscheduled capacity, that capacity should be made available unless it is physically unable to operate or otherwise limited. For example, the ISO will not deem a generator to be available once the generator informs the ISO that it is unavailable due to a forced outage, or if responding to a

[51] Only non-hydro PGA resources and designated ACAP resources are required to offer into RUC.

Dispatch Instruction would result in loss of QF status, loss of an environmental permit, or criminal penalties. MD02 Filing, Attachment A at 155. A resource should not, however, be withheld at the unfettered discretion of the resource owner.

With regard to municipal utilities and other governmental entities, the MSS concept provides for these entities to reserve their own resources to serve their own load requirements first. To the extent that a MSS identifies resources it is reserving to meet its own load, the ISO will not commit other resources in RUC to cover a shortfall in that MSS' day ahead schedule, nor will it commit that MSS' identified resources to cover the load of other LSEs.

3. The RUC Procedure Appropriately Procures Both Capacity and Energy in the Near Term

CMUA praises the RUC process for moving the capacity procurement role to a day-ahead time frame. However, CMUA states that, because the RUC process will be used to buy both capacity and energy, the RUC process "will undermine efforts to ensure that LSEs have adequate capacity rather than rely on ISO procurement." CMUA further states that PJM and the New York ISO seek to minimize the costs of RUC capacity commitment and, therefore, only purchase "minimum load" energy through RUC, and that the ISO should follow this approach. CMUA at 13-15. Sempra agrees with this position and urges the Commission to restrict the objective function of the RUC service to start-up and minimum generation bids. Sempra at 9. *See also* TANC at 12-13.

The ISO recognizes and shares the stated concerns and has structured the RUC procedure to reduce its energy procurement aspect as the phases of MD02 implementation proceed. Once ACAP is fully effective, the RUC procedure will consider only ACAP and other must offer (*i.e.*, non-hydro PGA) resources. Prior to that, once the ISO establishes a day-ahead energy market, it will be possible for import suppliers to offer energy into that market to be cleared against load bids, and the need for the ISO to purchase import energy day ahead will diminish. In the near term, however, the ISO believes that these intervenors' proposals are not workable. Unlike the eastern ISOs, California is very dependent on imports and, as such, needs to consider the energy bids from interties not backed with a visible resource and confirm them on a day-ahead basis. If the ISO were to limit the RUC process to committing capacity from internal generation, the ISO would likely be deficient in many hours. At the same time, it is not practical to "commit" intertie resources in the same way that RUC will commit internal resources, because (1) intertie energy is typically not tied to a specific resource, so that a commitment decision is not physically meaningful, and (2) intertie resources are not subject to a must-offer obligation and will likely want to sell firm energy on a day-ahead basis. The point is that internal resources and import supplies are two very distinct products from the point of view of a reliability procurement such as RUC. Yet the ISO needs some quantity of both in order to ensure sufficient supply, and needs a way to optimize its procurement of these two different products. Therefore, the ISO uses an optimization that includes the energy bids as well as the start-up and minimum-load bids for internal resources, which have no counterpart for the imports. Given California's dependence on imports and the need to implement MD02 in phases, the ISO believes it is appropriate to consider in the RUC process both internal supply capacity and available supply from imports. This necessitates a cost minimization approach that considers both energy and capacity. In this manner the ISO's proposal allows the ISO to procure sufficient resources to ensure reliable operation of the grid.

4. The Methodology Used to Determine the Amount of RUC Procurement On Any Given Day Is Reasonable

a. The RUC Process Is Designed to Minimize the Risk of Over-procurement

SCE states that the ISO may be conservative in its RUC decisions and consistently over-commit generation under the RUC process, such that the ISO has an excessive number of units being paid to be available on most days and in most hours. SCE suggests that the ISO's RUC decisions should be monitored by the Market Monitor, and the ISO's RUC authority should be suspended or limited if it is determined that the ISO consistently over-commits generation in excess of actual requirements. SCE at 25-26. Likewise, NCPA suggests that the Commission impose a performance reporting mechanism that would allow market participants to evaluate the prudence of the ISO's RUC decisions. NCPA at 12.

These intervenors ignore the fact that the RUC process includes very specific parameters on the process' capacity and energy procurement targets to ensure that the proper amount of capacity and energy – no more and no less – is procured. MD02 Filing, Attachment A at 107-09. For example, the ISO's energy procurement is limited to a maximum of 95 percent of the next day's hourly load forecast, with the remaining 5 percent serving to allow for load forecast error, to minimize the risk of over-procurement of energy by the RUC, and to avoid creating an incentive for loads to under-schedule in the day-ahead market. MD02 Filing, Attachment A at 107.

It is important to realize, however, that the RUC procedure is based on forecasts, and therefore the ISO cannot assure that RUC will never result in over-procurement. In this regard, the ISO takes seriously its objective of achieving reliability at minimum cost and will continue to monitor the RUC procedure and adjust the procurement as appropriate. However, while it is necessary continuously to evaluate the accuracy of RUC and to make adjustments, it is dangerous to assess prudence after the fact when the ISO must make decisions prior to real time based on the best information available at the time decisions are made. In this respect, the RUC reliability procurement is like fire insurance, which can easily be judged imprudent after the fact if the house did not burn down.

MWD asserts that the RUC process is unnecessary in off-peak periods because there is plenty of uncommitted capacity available in such periods. For this reason, MWD asks the Commission to authorize the RUC process to operate only for on-peak periods. MWD at 8-10. The ISO believes that such a restriction is arbitrary and could undermine the purpose of RUC by making it unavailable in hours when it could be needed most. The RUC process should be available in all hours, including off-peak hours, if only to ensure the provision of reliable service in the extraordinary circumstances that MWD cites (MWD at 9). In any case, MWD should have no complaint about the RUC process being authorized for off-peak periods, because if there is enough uncommitted capacity available in these periods as asserted by MWD, the RUC process will not procure anything.

b. The Ninety-Five Percent Ceiling on Energy Procurement Alone Under the RUC Process Is Reasonable

Bonneville argues that by applying the upper limit on total energy at 95 percent of its forecast, the ISO creates an undue bias that favors in-state resources over imports, and requests the Commission to direct the ISO to apply the 95 percent ceiling in a manner that does not solely reject import bids. Bonneville at 5-6. *See also* Reliant at 14. Bonneville does not recognize that the ISO's proposal to incorporate import bids in RUC provides a means that would not otherwise exist for the ISO to procure import energy day ahead. The 95 percent limit is a safeguard against over-procurement of day- ahead energy which is needed because import bids in RUC are typically not available as true unit commitment bids. Those imports that are backed by visible resources and submit three-part bids can be selected in the RUC process as part of its 100 percent capacity procurement target. MD02 Filing, Attachment A at 29. The fact is, as discussed above, that internal resources and import supplies are not the same product from the viewpoint of a reliability procurement. It is not possible to ignore the differences and still satisfy the objectives of RUC. Thus, the RUC proposal is shaped by the problem it is trying to solve and is not unduly discriminatory.

MWD asserts that the ISO has provided no empirical evidence to demonstrate the accuracy of its proposed Adjusted Demand Forecast. MWD suggests that the 95 percent ceiling should be applied to the capacity amount of all resources committed through RUC, and not just the energy produced from such resources. MWD at 13-15. The ISO forecasts are public records. The 100 percent capacity procurement target ensures enough capacity is available in the real time market. Only the minimum load energy from this capacity is guaranteed by the ISO while the rest of the capacity is subject to competition in the real time market. The ISO believes that committing less capacity than it forecasts it will need to serve real-time needs could seriously undermine reliability.

5. The RUC Process Does Not Present Increased Opportunities For "Gaming the System"

SCE states that the combination of the RUC process and market bidding rules in the hour-ahead market provide opportunities for "gaming the system" and unnecessary cost exposure to LSEs by allowing parties to "undo" the commitments made in the day-ahead market or in the RUC process without facing the appropriate cost consequences. SCE presents the following scenario. Because the ISO proposes to determine the need for RUC commitment based on a comparison of day-ahead schedules and its forecast of real-time demand, LSEs could over-schedule demand in the day-ahead market so they would never have a deficit; SCE states that this could lead the ISO to conclude that no additional unit commitment was necessary in the RUC process, thereby avoiding any RUC costs. An LSE could then revise its demand schedule downward in the hour-ahead market to reflect its expected actual demand.

The ISO does not believe the scenario SCE presents is a viable strategy. First, there is no reason for the LSE to over-schedule day ahead and then reduce its schedule to the realistic level hour ahead. To avoid day-ahead RUC costs, it is sufficient to schedule accurately expected load in both day-ahead and hour-ahead markets. Second, the LSE that tries to avoid RUC costs through strategic scheduling will face significant risks. Consider first the near term market structure in which the balanced schedule requirement is in effect and the ISO conducts only a day ahead RUC procedure (October 1, 2002 until spring 2003). In this situation, the LSE may be short of supply resources, so to avoid RUC costs it would accurately schedule its expected load matched by artificial supply in day ahead. If the artificial supply is from internal resources, those resources would be held accountable by the ISO to stand by their day ahead commitment and could not simply disappear after the day ahead market. Alternatively, if the artificial supply is from imports, the LSE would risk substantial congestion costs to schedule imported supply it does not really have, and would risk high real-time energy on top of that to serve the load that had been scheduled against the artificial supply.

Now consider the long term market structure, beginning in spring 2003, when the balanced schedule requirement has been eliminated, the ISO operates forward energy markets and performs both day ahead and hour ahead RUC procedures. In order to avoid day ahead RUC costs, the LSE that is short of supply would either have to submit a balanced bilateral schedule containing artificial supply (and face the same risks as in the previous case, plus exposure to hour ahead RUC costs), or would have to submit adequate demand bids to purchase energy to meet its actual expected load. The latter option is simply the legitimate arbitrage that the proposed long-term design allows. That is, the LSE is choosing to pay a higher price for day-ahead energy so that it will avoid exposure to RUC costs.

Finally, there is an additional incentive built into the RUC to discourage supply-short LSEs from trying to avoid RUC costs through strategic scheduling. Under the ISO's RUC proposal, capacity committed in RUC is selected based on day-ahead energy bid curves which cannot be revised upward in subsequent markets. By avoiding the RUC process, an LSE runs the risk that a supplier not selected in RUC will realize that a significant amount of load has under-scheduled and will submit high energy bid curves into the ISO real-time market to meet that load. In this regard, the ISO's proposal is consistent with SCE's suggestion that the ISO require that bids in the hour-ahead market can only reduced from the day-ahead market. SCE at 20-21.

MWD objects to the ISO providing only System Resources with the ability to submit a block bid through the RUC process. MWD contends this creates the potential for gaming and manipulation and may artificially increase the cost of Energy. MWD asserts that the ISO has provided no explanation of the rationale for allowing only System Resources to submit block bids. MWD at 16-17.

MWD's concern that only System Resources can submit block bids is based on a misconception. In fact, the minimum load bid from an internal resource is a 24-hour block bid for the minimum load energy. When the RUC commits an internal resource, it commits the resource for the entire operating day, not for individual hours. Thus, the RUC procedure is comparing 24-hour blocks of minimum load energy for internal resources with the block bids submitted by System Resources. Further, the ISO does not believe that allowing System Resources to submit block energy bids will lead to gaming or market manipulation. Block energy is a standard energy product and is typically offered to the market at a discount compared to buying an equivalent amount of hourly products. Therefore, the ISO believes that allowing block energy bids may actually reduce market costs. Indeed, the ISO would not procure block energy bids unless they were economic. California is highly dependent on imports and, as such, needs to consider the energy bids from intertie energy not backed with a visible resource. At times, these bids come only as blocks.

6. The Process for Determining Which Generators May Participate In the RUC Process Is Reasonable

SMUD objects to the RUC process insofar as it will only allow for input of a single ramp rate in determining which units to select for the RUC process.

Because units do not have a single, constant ramp rate across their entire operating range, SMUD asserts that the ISO should upgrade its software to allow for the consideration of variable ramp rates. SMUD at 16-17. The MDO2 design has recognized this need and will utilize multiple ramp rates. Sempra objects to the exclusion from RUC of generating units that have not been designated as capacity or must-offer generating units. Sempra asserts that it makes no sense to commit a unit obligated to be available if another unit will "volunteer" to be committed at a lower overall cost.[52] Sempra at 10. Sempra also states that once the ISO implements its integrated day-ahead energy and ancillary services markets, it should integrate and optimize the RUC process with the day-ahead unit commitment and congestion management process so that the most efficient overall mix of generators are committed to serving the total load that the ISO expects to materialize the next day. Sempra at 10.

Sempra seems to be advocating a day-ahead energy market that is based on the ISO forecasted load rather than the demand bids submitted by individual market participants. The ISO favors a bid based day-ahead market as this approach (1) keeps the ISO out of the day-ahead energy market as a buyer; (2) provides LSEs with greater flexibility in using the different market time frames to meet there demand, and (3) is consistent with the market structures of the eastern ISO which run a day-ahead market based on demand bids submitted by market participants, followed by a distinct reliability commitment based on the ISO load forecast.

[52] As indicated above, the ISO will consider volunteer units but will give first priority to ACAP resources.

One of the obligations of a resource that is paid and designated as ACAP is to offer its capacity in the day-ahead markets and be available for RUC with any non-committed capacity. The ACAP obligation is designed to ensure that adequate supply will be available to meet real time load and reserve needs. With a fully implemented ACAP obligation, the RUC process is simply a tool for the ISO to commit ACAP resources that the LSEs may, for whatever reason, fail to schedule. In those instances where ACAP resources may be inadequate, due perhaps to an unusual facility outage situation, RUC will be able to call upon other non-hydro PGA resources that have available capacity under the must offer obligation. Such limitations on RUC eligibility are fundamental to the design of RUC as a reliability procedure, not another market.

7. The Proposed RUC Methodology for Compensating Generators Is Appropriately Compensatory and Reasonable

A number of intervenors contend that the compensation methodology under the RUC process will result in under-compensation of generators.

CAC/EPUC argues that the compensation mechanism under the RUC proposal, by which generators will be paid a capacity payment calculated based on variable operating costs rather than a payment for capacity and fixed costs, will be insufficient to fully compensate generators for their costs and will deny generators full compensation based on market rates. CAC/EPUC at 4.

The CAC/EPUC argument is based on a misconception of the RUC payment structure, including the capacity payment, and of the RUC procedure itself. The RUC procedure is designed to be a reliability tool, not a market.

Similarly, the RUC payment structure is designed to cover the costs associated with a particular commitment decision, if that decision comes from the ISO. This is appropriate because a resource that is committed by the ISO is one whose owner has decided not to operate on a given day because of perceived lack of opportunity to make a profit. If the ISO wishes to override the owner's decision and commit the resource, the ISO will be responsible to ensure that the resource does not suffer a loss as a result. This responsibility is reflected in the guarantee of start-up and minimum load costs, which include a payment of $6 per MWh of minimum load for fixed O&M costs.[53] In this respect, the ISO's proposal is fully consistent with the procedure and compensation structure used by other ISOs to compensate generators for the commitment to be up and running and available for dispatch in the operating day. *See infra* at 85-86. A resource's fixed costs can be recovered through their market-based energy bids, and through contracting with a LSE to provide capacity.

In the ISO's proposal for the interim period (*i.e.* until ACAP is implemented), the RUC capacity payment has a well-defined purpose. Once a RUC-committed resource is up and running at minimum load, the resource owner may decide to capitalize on the ISO's subsidization of its start-up and minimum load cost by seeking new opportunities to participate in the various markets. If the resource finds an opportunity to export its power, then of course that power is no longer available to serve California load. The ISO therefore offers the RUC

[53] As the Commission has previously recognized, a $6.00 O & M adder "should permit generators in the California market full recovery of all non-fuel expenses." June 19 Order at 62,563.

capacity payment as a reasonable retainer to induce the resource owner to reserve its unloaded capacity for California load. The capacity payment is in addition to guaranteed compensation for start-up and minimum load costs. In the event that the ISO dispatches this capacity in real time – which will be in accordance with the resource's market-based energy bid as submitted to the RUC procedure – the resource earns the market clearing price in lieu of the capacity payment for the amount of energy dispatched.

Edison Mission asserts that the RUC procedure should allow recovery of a gas-fired generator's actual start-up and minimum-load costs, rather than determine recovery of costs based on the formula provided in the MD02 proposal, if the actual costs are in excess of the formula-determined costs. Edison Mission at 3-5; s*ee also* IEP at 11; Williams at 17-18. The Commission has addressed this issue on numerous occasions in its orders regarding price mitigation in California. For instance, in its May 15, 2002 "Order on Rehearing and Clarification" in Docket Nos. EL00-95-056, *et al.* the Commission stated at page 9: "Generators who are dissatisfied with this finding regarding cost recovery of only minimum load costs may propose cost-based rates for their generating units." Intervenors offer no new arguments to support their position. Consistent with its prior decisions, the Commission should reject these claims.

Edison Mission also states that the RUC process could result in a unit being started up and shut down frequently, which could lead to the wasteful use of emission credits. Edison Mission states that the RUC process should be modified to limit the number of start-ups and shut-downs for gas-fired units, or an emissions value should be included in the start-up cost portion of the three-part bid. Edison Mission at 5-8. Santa Clara states that the affected unit owner/operator must be compensated for cold start and minimum load running costs, and compensation should be paid to air-quality constrained units that are affected as a result of the RUC operations. Santa Clara at 10-11. The ISO notes that, in prior orders, the Commission has directed the ISO to pay to generators, as a separate uplift, emission costs incurred by generators that are required to run in compliance with ISO dispatch instructions. *See* June 19 Order at 62,562. Under the existing procedures, generators submit invoices to the ISO for mitigation fees that they incur.

Duke states that it objects to the ISO's proposal to provide recovery of start-up and minimum load costs, net of market profits during the next 24-hour operating day (and subject to restrictions on self-scheduling and uninstructed deviations). Duke at 17 & n.46 (citing May 1 MD02 Filing, Attachment A at 107-08). IEP also objects to such netting, saying that it will only serve to distort bidding in the ancillary services markets because facilities will account for the lost payment guarantee in their AS bids. IEP at 17; see *also* Reliant at 12, 14.

The Commission has approved a "net-of-market" approach for PJM, NYISO and ISO New England. [54] It is axiomatic that an agency must conform to its prior practice and decisions or explain the reason for its departure from such

[54] For example, Sheet 119 of the PJM Operating Agreement provides: "Payment to Generator = MWH Adjustment * (unit offer price – marginal price at the generator bus) = any applicable start-up or no-load costs not recovered by the marginal price." Sheet 95 of the New York Operating Agreement provides: "Generating Units committed by the ISO for service to ensure local reliability will recover startup and minimum generation costs not recovered in the Dispatch Day." *See also* Attachment C to the NYISO Tariff, First Revised Sheet No. 421, *et seq.*

precedent. *See United Municipal Distributor Group v .FERC,* 732 F. 2d 202,210 (D.C. 1984); *Greater Boston Television Corporation v. FCC,* 444 F.2d 841, 852 (D.C. Cir.), *cert. denied,* (1971) (agency must give reasoned analysis for departures from prior agency practice). The Commission must conform to this mandate. Specifically, consistent with its decisions in PJM, NYISO and ISO New England, the Commission must permit the ISO to "net" start-up and minimum load costs in the RUC process. Intervenors have not provided any valid reasons why the Commission should treat the ISO differently than it has treated every other independent system operator. The generators' objections to netting essentially amount to the generators wanting to "have their cake and eat it too". The generators' position contemplates that, having been paid minimum load and start-up costs, they can then freely participate in bilateral agreements and ISO markets, retaining all of the profits by selling their remaining capacity through their market based rates. This approach could cause market participants to subsidize the generators' other market activity or possibly pay twice for the same energy. That is wholly inappropriate.

Williams asserts that the ISO's bid mitigation approach and minimum load payment guarantees are too restrictive. Williams also asserts that suppliers should have the ability to change bids from the day-ahead to the hour-ahead market. Williams at 17-18.

The MD02 Filing does allow suppliers to change bids between the day-ahead RUC and the hour-ahead market for the any capacity that is not selected in the day-ahead market or day-ahead RUC process. Suppliers also can also reduce their energy bid prices for capacity selected in the day-ahead market and day-ahead RUC; however, suppliers cannot increase them. Allowing suppliers to increase energy bids for capacity selected in the day-ahead market and in the RUC process is inappropriate because that capacity was selected in the day-head market and day-ahead RUC based on an explicit consideration of the energy bids submitted at that time. Allowing them to increase those bids would invite gaming and undermine market efficiency.

MWD states that the proposed methodology for selecting and compensating hydroelectric generating units is the same as the methodology applicable to thermal units, and that it does not reflect fundamental differences in the operational costs and characteristics of hydroelectric units. MWD proposes that hydroelectric units be given the same flexibility extended to Curtailable Demand which, through the Minimum Curtailment Payment, is able to simply set a figure to be paid if it is committed through the RUC process, regardless of the quantity or duration of the accepted bid. MWD at 10-13. MWD also contends that the Minimum Hourly Payment is unnecessary, as Scheduling Coordinators submitting bids for Curtailable Demand already have discretion in submitting a Minimum Curtailment Payment bid. MWD at 15-16.

It is not appropriate to treat hydroelectric resources the same as Curtailable Demand with regard to start-up and minimum load compensation in RUC. This compensation is intended to be cost based. For hydroelectric resources, the costs associated with a RUC commitment are identifiable, and the ISO's proposal is to compensate those costs. For Curtailable Demand, however, there is no straightforward approach to calculating and verifying such costs, so the ISO proposes to allow Curtailable Demand to bid a start-up/minimum load equivalent, namely, the Minimum Curtailment Payment. Since RUC-associated costs for hydroelectric resources are already covered in the ISO's proposal, there is no justification for paying these resources a bid-based Minimum Curtailment Payment. If suppliers believe there are legitimate commitment costs that have been omitted from the ISO's proposed payment, these suppliers may submit documentation of these costs to the ISO for consideration. Finally, the ISO notes that hydroelectric resources are not required to participate in the RUC procedure (unless they are designated ACAP resources), so if suppliers believe the RUC payment structure is inadequate they need not offer hydroelectric capacity to RUC.

Dynegy states that a RUC dispatch payment should include a rate of return (e.g., 13-15 percent in accordance with existing risk conditions). Dynegy at 19-25. Because the ISO is guaranteeing full recovery of startup and minimum load costs and units can submit market based energy bids for any incremental energy dispatch, the ISO is unclear as to what "risk conditions" Dynegy is referring to. As noted above, the RUC issues commitment orders to resources that had decided not to self-commit because their perceived opportunities for the next day were not attractive. The ISO's proposed compensation for RUC commitment ensures that the resource is no worse off than it would be by not running at all. No other ISO permits units to recover a return on equity in connection with start-up and minimum load costs. If Dynegy wants to earn a specified return on equity it should do so through a bilateral contract or file for cost based rates for its generation units.

Reliant objects to the RUC procedure, asserting that it would not make generators whole. Reliant also objects to cost-based pricing, on the grounds that sellers should submit bids for the capacity and energy portions of a RUC instruction. It asserts that sellers should be able to change those bids subject to seasonal or six-month limits so that bids remain competitive but are not subject to short-term price volatility. In addition, Reliant contends that some compensation for lost opportunity cost is appropriate, along with fuel risk, credit risk, peaking unit availability value, and a reasonable target margin. Reliant at 9-10, 14-16.

Suppliers can submit market based bids for the energy portion of their three-part bid and those energy bids can reflect opportunity cost for energy limited resources. Only the start-up and minimum load are cost-based. The Commission has approved cost-based pricing for start-up and minimum load costs in connection with the must offer obligation. *California Independent System Operator Corporation, 97 FERC ¶61, 293 (2001).* There is no is no legitimate reason why the pricing of start-up and minimum load costs should be any different under RUC. Besides, if the ISO had not committed the resource, the resource would have been shut down and would not have earned anything. Credit risk is not an issue because the Commission and the ISO Tariff have made it very clear that the ISO market must be backed by creditworthy buyers.

In contrast to the intervenors who assert that the RUC compensation methodology will result in underpayment of generators, SCE asserts that the methodology would in some cases overcompensate generators. SCE objects to the Tariff language that would pay units that were partially committed in the day-ahead market, and also committed in the RUC process, for start-up and minimum load costs. SCE states that this would be excessive since those costs would already have been incurred to meet the day-ahead market commitment. SCE suggests that the Tariff language should clarify that units with day-ahead schedules are not eligible for startup or minimum load payments under the RUC process. SCE at 22-23. SCE misreads the ISO's proposal on this point. The ISO never intended that units with day-ahead schedules be eligible for start-up or minimum load payments.

SCE also expresses concern that in some circumstances a unit could receive a RUC capacity payment that is not merited, by generating energy out of RUC-committed capacity without having received an ISO dispatch instruction. SCE states that the Tariff should be corrected to make such a unit ineligible for capacity payments in the RUC process. SCE at 23, referencing Section 5.12.7.1.3 of the ISO Tariff. The ISO acknowledges SCE's point, and will correct this tariff section in its upcoming MD02 Tariff filing so that the RUC capacity payment will be withdrawn for uninstructed deviations.

8. Use of Daily Gas Indices Is Inappropriate

Reliant argues that the natural gas component of RUC's cost-based compensation must be based on spot gas costs. Reliant at 15. The Commission has rejected the use of a daily index (rather than a monthly index) on several occasions and should again reject such arguments. *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange Corporation*, Docket No. EL00-95 *et al*., "Order on Rehearing and Clarification," slip op. at 11-12 (May 15, 2002) ("May 15 Order"). June 19 Order at 62,561; December 19 Order at 62,204. The Commission expressly found that use of a monthly gas price methodology "will not impede suppliers' recovery of operating costs." December 19 Order at 62,204. The Commission has also found that the average pricing formula "represents a reasonable price for the marginal costs that generators will incur since they can pre-buy their gas requirement for the month at this price."[55] June 19 Order at 62,561. Moreover, the average monthly gas price has consistently been within a reasonable range of the daily spot market price. May 15 Order, slip op. at 11.

9. The Proposed Methodology for the Allocation of Costs Incurred In the RUC Process Is Reasonable

The ISO has explained that it most cases it will be able identify the amount that a Scheduling Coordinator failed to schedule in the forward markets. MD02 Filing, Attachment A at 160. However, the ISO has also explained that "[r]esidual unit commitment, because it is a procurement process based on a day ahead

[55] The Commission has noted correctly that the use of the average gas price is reasonable because generators generally pre-buy their monthly gas requirement rather than purchase gas on the daily spot market. May 15 Order, slip op at 11. Reliant's suggestion that generators purchase spot gas for their generation units that operate on a regular basis is unfounded and illogical.

load forecast and hence is vulnerable to forecast error, is one area of financial settlement that introduces the socialization of costs out of necessity." MD02 Filing, Attachment A at 160. The ISO has clearly described the proposed RUC allocation methodology and the rationale for that methodology. MD02 Filing, Attachment A at 160-66.

In light of these considerations, intervenors are wrong in their assertions that the RUC cost-allocation methodology should be altered. CDWR at 9; CMUA at 15-17; SCE at 23-25; SMUD at 15; TANC at 13.

K. The Commission Should Approve the ISO's ACAP Proposal in Order to Ensure Reliable and Efficient Operation of the ISO Grid and Markets[56]

1. The Commission Has Jurisdiction to Impose an ACAP Obligation

The California Public Utility Commission on behalf of the California Inter Agency Working Group ("CPUC/IAWG") claims that the ISO's ACAP proposal represents an expansion of the ISO's role into resource procurement that is traditionally a State function. CPUC/IAWG at 41. CPUC/IAWG contend that appropriate reserve margins should be determined at the state not the federal

[56] On May 15, 2002, the ISO filed a Motion For Rejection of, or In the Alternative, Answer To, Motion of Reliant Companies For Establishment Of A Capacity Market. That motion addressed the merits of Reliant's proposal for an interim ACAP mechanism and a long-term Regional Reliability Commitment. The ISO hereby incorporates its Motion by reference. The ISO notes that in its tariff filing being made simultaneously herewith, the ISO compares the relative merits of certain aspects of its ACAP proposal with aspects of Reliant's capacity proposal and the Advisory Forward Energy Commitment proposal of CPUC/IAWG. The ISO will not repeat that discussion herein.

level. *Id*. at 43. The CPUC/IAWG and the California Department of Water Resources State Water Project (SWP) object to the ACAP proposal because it purportedly imposes a capacity obligation on wholesale purchasers of electricity, but the FPA only regulates sellers of electricity. CPUC/IAWG at 43; SWP at 8.

The ISO submits that the Commission clearly has jurisdiction to impose an ACAP obligation on LSEs. Indeed, going as far back as the mid-1970s, the Commission has found it appropriate to impose a capacity obligation on LSEs participating in power pools. *New England Power Pool Agreement*, 56 FPC 1562 (1976) (approving Capability Responsibility obligations on NEPOOL's electric utility participants based on each participant's system peak compared to the aggregate peaks of all participants). In approving a capacity obligation for NEPOOL LSEs, the Commission stated that "[s]uccessful operation of NEPOOL requires that to the greatest extent possible each participant should develop sufficient capacity to meet its load." *Id.* Moreover, the Commission has approved capacity obligations for LSEs in each of the eastern ISOs. *PJM Interconnection LLC and Allegheny Power*, 96 FERC ¶ 61,060 at 61,212-14 (2001)("PJM West")(approving PJM West's ACAP requirement which imposes a daily capacity obligation on LSEs equal to 106 percent of the total day-ahead estimated load requirement coincident with the zone peak for that LSE); *ISO New England*, 91 FERC ¶ 61,311 at 62,080 (2000)(LSEs must acquire generation capacity equal to their peak load plus a reserve margin); *Pennsylvania-New Jersey-Maryland Interconnection, et al.*, 81 FERC ¶ 61,257 (1997),*0order on clarification*, 82 FERC ¶ 61,008 (1998), *order on rehearing*, 92 FERC ¶ 61,282 (2000) (approving

Reliability Assurance Agreement which requires each LSE to own or purchase capacity resources greater than or equal to the load that it serves, plus a reserve margin); *New York Independent System Operator, Inc.*, 90 FERC ¶ 61,319 (2000), *amended*, 96 FERC ¶ 61,251 (2001)(approving an ICAP obligation on LSEs utilizing a UCAP methodology).

Given that the Commission has imposed capacity obligations on LSEs in other ISOs, there is no rational basis for SWP and CPUC/IAWG to argue that the Commission lacks jurisdiction to impose a capacity obligation on LSEs in California. Indeed, in a prior order, the Commission expressly directed market participants in California to consider (1) the creation of an installed capacity market and (2) the establishment of reserve requirements. December 15 Order at 62,017. It is difficult to conceive that the Commission would have directed California market participants to consider implementation of these mechanisms if the Commission lacked the jurisdiction to impose them.

The argument that the ACAP proposal would impose obligations on buyers of electricity that are not regulated under the FPA misses the point. The ACAP obligation is not being imposed on buyers. It is being imposed on entities serving load in the ISO Control Area. LSEs and/or their agents utilize the ISO transmission grid and/or participate in ISO markets. The ACAP obligation is intended to ensure that adequate capacity resources are available to provide reliable service to loads in the ISO Control Area and to coordinate planning of capacity resources consistent with WECC reliability standards. The Commission has jurisdiction under the FPA to impose an ACAP obligation on LSEs as a condition of utilizing transmission service, and the ISO's ACAP proposal is consistent with the requirements of Order No. 2000.

FPA Sections 205 and 206 grant the Commission the authority and responsibility to ensure that the rates, charges, classifications and service of public utilities (and any rule, regulation, practice or contract affecting any of these) are just and reasonable. 16 U.S.C. §§ 824d and 824e. Section 202(a) of the FPA empowers the Commission to:

> divide the county into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission and sale of electric energy, and it may at any time thereafter make such modifications thereof as in its judgment will promote the public interest. Each such district shall embrace an area which, in the judgment of the Commission can economically be served by such interconnected and coordinated electric facilities. It shall be the duty of the Commission to promote and encourage such interconnection and coordination within each district and between such districts.

16 U.S.C. § 824a. Section 205 of the Public Utility Regulatory Policies Act, 16 U.S.C § 824a-1, also supports the Commission's authority to encourage and support regional coordination. This section, which addresses power pooling, gives the Commission authority to exempt electric utilities from state laws or regulations that prohibit or prevent voluntary coordination , and to recommend to utilities to enter voluntarily into negotiations for pooling arrangements where opportunities for conservation, efficiency and increased **reliability** exist.[57] Consistent with this statutory authority, in Order No. 2000, the Commission sought to advance the formation of RTOs as a means for enhancing grid **reliability,** improve efficiencies in transmission grid management and promote

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[57] The Commission has previously interpreted Section 205 of PURPA as essentially complementing the functions under Section 202(a) of the FPA. *Public Service Company of New Mexico*, 25 FERC ¶ 61,249 at 62,038 (1983).

regional coordination. *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & . Regs. [Regulations Preambles 1996-2000], ¶ 31,089 at 30,933, 31,044-45 (2000).

A consistent line of judicial precedent supports the Commission's authority to approve the terms of pooling and coordination agreements of an integrated power system (which the ISO is). *See Mississippi Industries v. FERC*, 808 F.2nd.1525 (D.C. Cir. 1987)("*Mississippi Industries*"). The Supreme Court has found that the integration of utilities is a "practice" as defined under the FPA, and the Commission has the authority under FPA Sections 205 and 206 to determine the terms suitable to such integration of utilities. *Pennsylvania Water & Power Company v. FPC*, 343 U.S. 414 (1952). In particular, the Commission has the authority to order a purchase or sale of power where such order is consistent with the integration of a power pool or network. *See Mississippi Industries*, *supra* (affirming a Commission decision which required a utility to purchase a specified percentage of high-cost nuclear power from another affiliate of the holding company).[58] In numerous instances, the courts have upheld Commission decisions approving capacity and/or purchase obligations on LSEs in connection with integrated power network operations.. *See*, *e.g*. *Ohio Power Company et al. v. FERC*, 668 F.2d 880 (6th Cir. 1982); *Central Iowa Power Cooperative, et al. v. FERC*, 606 F.2d 1156 (D.C. Cir. 1979); *Municipalities of Groton, et al. v. FERC*, 587 F.2nd 1296 (D.C. Cir. 1978).

[58] The Supreme Court has recognized the Commission's jurisdiction to order allocations of power under certain circumstances and ruled that states may not alter such allocations of power. *Mississippi Power & Light v. Mississippi*, 487.US.3546 (1988).

Consistent with this relevant case law, the Commission has approved capacity obligations for LSEs as a measure to ensure that adequate capacity resources are planned and made available to provide reliable service to loads within a control area, to assist other parties during emergencies and to coordinate planning of capacity resources consistent with reliability principles and standards. 95 FERC at 62,174; 91 FERC at 60,080. Like the other capacity-type obligations the Commission has approved (and courts have affirmed), the ISO's proposed ACAP obligation will support the reliable and efficient operation of an integrated, interstate transmission network and interstate wholesale market by requiring LSEs to procure in a forward market timeframe resources sufficient to satisfy the ISO's peak daily operating requirement. As the case law discussed above clearly provides, the Commission has the jurisdiction and the authority to approve capacity obligations that further the reliability of an integrated interstate transmission grid. Further, the Supreme Court has recognized that the Commission has the "responsibility to the public to assure **reliable**, efficient electric service." [59] *Gainsville Utilities Department, et al. v. Florida Power Corporation*, 402 U.S. 515 (1971) (emphasis added). This is exactly what the ACAP proposal is designed to accomplish.[60]

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[59] The recent Supreme Court decision regarding the appeal of Order No. 888 recognized that the Commission has broad authority over the interstate transmission of electricity. *New York, et al. v. FERC,* 122 S. Ct. 1012 (2002). This decision further supports the Commission's authority to impose an ACAP obligation on LSEs.

[60] The ISO notes that the the WSCC Reliability Management System (RMS) which requires participants to adhere to reliability criteria (including maintaining sufficient Operating Reserves) and contains sanctions for failures to comply with the criteria. The Commission found that the RMS significantly "affects or pertains to" rates and charges by public utilities subject to the Commission's regulations. *Western Systems Coordinating Council,*.87 FERC ¶ 61,060 (1999). If the Commission has jurisdiction over the WSCC's imposition of reserve requirements over the

CPUC/IAWG contend that the ACAP proposal will federalize resource procurement that is traditionally a state role. CPUC/IAWG at 41,43. This claim is misplaced. In its order granting PJM RTO status, the Commission ruled that PJM, under the Reliability Assurance Agreement, has the authority to set region-wide capacity reserve requirements. *PJM Interconnection, LLC*, 96 FERC at 61,212(2001). Further, the Commission expressly found that its ruling did not intrude upon the states' traditional role in setting generation reserve requirements for load serving entities (e.g. maintenance of specific reserve requirements). *Id.* at n.16.   Likewise, the ISO's ACAP proposal does not unnecessarily or inappropriately intrude on the CPUC's role with respect to resource procurement. The CPUC will have discretion to determine how investor owned utilities (IOUs) satisfy their ACAP obligation (*e.g.* whether from utility-owned generation, long or short-term contracts demand resource). Further, the CPUC can order IOUs to maintain a higher reserve margin that that imposed by the ACAP obligation. Thus, the CPUC will play a significant role in shaping IOUs' ACAP contracts. In any event, the Commission's "intrusion" into the procurement process is no different under ACAP than it is in connection with ICAP or the other instances where capacity/purchase obligations have been imposed on LSEs.

2. The ACAP Proposal Does Not Intrude On Federal Jurisdiction

Dynegy claims that the ISO will give the CPUC a central role in ACAP procurement by permitting the CPUC to determine how much capacity each IOU should purchase and whether the rate charge is just and reasonable. Dynegy at

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ISO, it must have similar authority to enable the ISO to ensure that entities using the ISO-controlled grid maintain sufficient resources.

46. Dynegy claims that the Commission makes this determination in the Eastern ISOs and should retain this role in California. *Id.*

Dynegy's protest (1) reflects an egregious misrepresentation the ISO's ACAP proposal and (2) is at odds with the Commission's stated views regarding the extent of its jurisdiction. Contrary to Dynegy's claim, the CPUC will not determine how much capacity each IOU must purchase. Rather, it is the ISO -- with Commission approval --that will determine the ACAP obligation applicable to each LSE. MD02 Filing, Attachment A at 46-47, 52. As is the case in the eastern ISO's, the Commission will determine whether the ISO's proposed deficiency change is just and reasonable. Similarly, it is the Commission -- not the CPUC -- that has jurisdiction to determine whether any specific contract for the sale of capacity to an LSE is just and reasonable. *Id.* at 52. The ACAP proposal does not "transfer" that authority to the CPUC. The ISO's proposal recognizes the appropriate roles of both the Commission and the CPUC. Consistent with its actions in the eastern ISO's (and as discussed *supra* in Section K.1.), the Commission has the jurisdiction to determine the ACAP obligation for each Local Reliability Area and each LSE. However, the CPUC has the authority to determine the appropriate portfolio of resources that IOUs can procure to satisfy the Commission-approved capacity obligation (so long as such portfolio of resources does not conflict with any Commission-approved ACAP guidelines.) This is consistent with the Commission's stated view that states have authority in such traditional areas as utility resource portfolios and the administration of integrated resource planning and utility buy-side and demand-side decisions. Order No. 888 at 31,782, n. 44.

To the extent Dynegy is claiming that the CPUC does not have jurisdiction to determine the specific mix of resources that a utility can procure to meet its ACAP obligation, such position is inconsistent with the Commission precedent. The Commission consistently has ruled that its wholesale ratemaking does not as a general matter determine whether a purchaser has prudently chosen from among available supply options. *Ameren Energy Marketing Company*, 96 FERC ¶61,306 (2001); *Central Vermont Public Service Corporation*, 86 FERC ¶61,194 (1998); *Doswell Limited _Partnership*, 50 FERC ¶61,251 (1990); *Pacific Power & Light Company*, 27 FERC ¶61,080 (1984). Dynegy cannot cite to any order – nor is there such an order -- where the Commission has determined the specific exact mix of resources that LSE's in the eastern ISOs must procure to satisfy their ICAP obligations.

3. The ISO Should Not Be Required to Implement On A Cookie Cutter Basis The Capacity Obligation Schemes In Place In The Eastern ISOs.

Dynegy notes that the ACAP proposal is inconsistent with other market designs. Dynegy at 43. Williams suggests that the ISO adopt an ICAP program like that in place in PJM. The ISO acknowledges that its ACAP proposal is different than the capacity obligations in the eastern ISOs. The ISO's proposal provides LSEs with slightly more flexibility and proposes more obligations on capacity resources than the capacity programs in other ISO's. However, the Commission needs to take into consideration the fact that California lacks the institutional framework and historical experience with respect to the imposition of capacity requirements. Traditionally, such resources were procured on an entity-by-entity basis through bi-lateral contracts. The ISO's proposal accommodates this approach, but also provides a platform for the development of the necessary institutional and regulatory mechanisms and commitments to ensure resource adequacy is the future.

The primary difference between the ISO's proposal and the ICAP schemes in place in the eastern ISOs is the availability requirement. The ISO's proposal ensures that adequate capacity is available to be committed on a daily basis to meet system load and the ISO's operating and regulation reserve requirements. An availability requirement is less necessary in the eastern ISOs that have significant reserve margins. Unfortunately, the ISO does not have this luxury and, as such, has a much greater need for capacity to be "available".

In any event, the concept of an available supply obligation is not a radical concept. In that regard, Option 2 for "Long Term Generation Adequacy" as set forth in the Commission's Options Paper is essentially an ACAP-type obligation. Further, the Commission approved an ACAP requirement for PJM West. *PJM Interconnection, L.L.C. and Alleghany Power*, 96FERC ¶ 61,060at 61,212(2001). The ISO's proposal is based loosely on the PJM West model and borrows some of the "best practices" of the other ISOs.

4. The Commission Should Approve ACAP Effective January 1, 2004

Mirant requests that the Commission require the ISO to implement the ACAP obligation simultaneously with implementation of the market mitigation measures. Mirant at 29-31. On the other hand, the ISO proposes that ACAP be implemented effective January 1, 2004.

The uncertainty of Pacific Gas and Electric Company's and Southern California Edison Company's financial status makes imposition of an ACAP requirement on October 1, 2002 problematic. It is neither appropriate nor practical to impose an ACAP obligation on non-creditworthy IOUs, which are not currently able to procure ACAP resources independently. Further, LSEs will need to have substantial lead time to meet any ACAP obligation. Delayed implementation of ACAP will put LSEs in a better position to negotiate ACAP arrangements and reduce the market power of suppliers. Given the CPUC's and EOB's complaints against sellers of electricity under long-term contracts with CERS, the Commission should be well aware of the problems associated with negotiating long-term power contracts in a hurried manner in a short period of time.

As a final matter, the ISO notes that ACAP is not intended for an entity like CERS that has stepped in only on temporary basis in order to backstop purchases in the absence of non-creditworthy utilities. Rather, ACAP is essentially a long-term planning tool for utilities, as well as a tool for ensuring reliability on the grid.

5. The ACAP Forced Outage Provisions Are Not Unreasonable

Dynegy claims that suppliers will not want to participate in the ACAP market because the proposal puts them at financial risk for forced outages. Dynegy at 45. Specifically, Dynegy objects to the fact that the ACAP proposal would require sellers at the time of a forced outage to go into the open market and replace the capacity. Dynegy contends that, as a result, suppliers will either incorporate this risk into the price or withhold capacity. *Id.*

The ISO does not believe that is has imposed an onerous requirement. A resource can eliminate any risk from a forced outage by notifying the ISO in a timely manner of the outage and having a comparable amount of capacity bid into the imbalance energy market.

6. Responses To Specific Intervenor Claims

Intervenors raise a variety of issues regarding the ISO's ACAP proposal. The ISO will address these issues seriatim below. The ISO submits that the specific concerns raised by intervenors do not warrant rejection of or revisions to the ISO's ACAP proposal.

Bonneville states that the real-time dispatch requirement in the ISO's ACAP proposal represents a significant problem for imports. Bonneville at 4-5. Bonneville explains that accepted scheduling practices in the West prohibit intra-hour schedule changes across control-area boundaries. Bonneville states that the ISO's proposal to require that ACAP resources be dispatchable in real time is in conflict with that accepted practice and thus will prevent resources external to the ISO's control area from providing ACAP. Id. BPA also states that the ISO's proposed non-performance penalties are onerous in instances where a transmission facility is out of service. Id.

The ISO disagrees with Bonneville that the real-time dispatch requirement represents an obstacle to resources located outside the control area from providing ACAP. First, the ISO notes that all the existing ISOs have comparable provisions in their tariffs that provide for participation in their capacity markets by resources external to their control areas, yet they also have comparable inter-control area scheduling restrictions. See NY ISO Installed Capacity manual, Section 4. While the ISO recognizes that there are stricter availability requirements for ACAP resources under the ISO's proposal than may be in place in the Eastern ISO's, these requirements do not represent an insurmountable hurdle to participation by a resource outside of the ISO's control area compared to one within the control area.

Second, the imported ACAP resources need not participate as dispatchable resources in real-time. Like all other ACAP resources, they must participate in the day-ahead market, and, if successful, they are scheduled for the full hour. To the extent they are unsuccessful in clearing the day-ahead market, they must participate in the Residual Unit Commitment and the hour-ahead markets – processes and markets that provide opportunities for them to be scheduled for the full hour. If they are unsuccessful in these markets, they can bid in Supplemental Energy, in which case they can still be pre-dispatched for a full hour. Even though they are then expected to follow real-time mid-hour dispatch instructions, they will simply be price takers (based on the 10-minute prices set by the dispatchable resources) if they cannot follow such instructions. Presumably the ACAP payment and their Supplemental Energy bidding strategy would be more than sufficient to cover such small risk. As noted earlier, the ISO's ACAP proposal contemplates that each LSE will proactively manage it own ACAP portfolio in order to optimize the use of its portfolio. Management of its ACAP portfolio will, by necessity, include managing the portfolio in a manner consistent with established scheduling practices. For example, a LSE that procures ACAP resources from outside the control area should be cognizant of any intra-hour scheduling constraints and thus should utilize (schedule) these resources in the DA by pre-committing to use these resources to serve its load (bilateral self-schedule). Once committed in this fashion, the *energy* can be delivered according to schedule. Moreover, as noted above, the operating constraints (i.e., limited scheduling flexibility over the ties) can be accounted for in the RUC process. Thus, the ISO believes that if appropriately managed by the Scheduling Coordinator representing a LSE, resources external to the ISO's control area can actively participate as an ACAP resource.

With regard to Bonneville's concern regarding the ISO's proposed non-performance penalties, to the extent that a resource is unable to satisfy its ACAP obligation because of a transmission line has either been derated or forced out, the ACAP supplier will not be penalized**.** In addition, the responsibility of ensuring the deliverability of an ACAP resource external to the ISO control area (through the reservation of transmission rights, backup support, etc.) will ultimately be based on the contractual agreement between the LSE and the ACAP supplier.

CDWR states that the ACAP proposal could drive LSEs into planning processes centered on the month-ahead horizon even if month-long contracts are not ideal. CDWR at 7-9. The CPUC/CIWG raise similar concerns. CPUC/CIWG at 39. The ISO disagrees that its ACAP proposal, as represented by CDWR and CPUC/CIWG, artificially limits ACAP resources/contracts to one month. As stated in the ISO's MD02 Filing, a LSE must demonstrate on a monthly basis that it has procured sufficient resources to satisfy forecast load plus a reserve margin. MD02 Filing, Appendix A at 46, 54, 58-59. To the extent that a LSE is ACAP-deficient on a month-ahead basis, that LSE must submit an amount of credible demand resources necessary equal to its deficiency MD02 Filing, Appendix A at 66. However, a LSE can, during the course of a month in which it is deficient, make up its deficiency by procuring sufficient resources on a weekly or daily basis. If successful in procuring sufficient ACAP to satisfy its daily obligations, the ISO may not have to call on the LSEs demand resources. Thus, while the ISO is requiring a LSE to identify an amount of resources (supply or demand) necessary to satisfy its obligation on a month-ahead basis, it is not prohibiting a LSE from entering into shorter-term supply arrangements to satisfy the obligation. CDWR is correct that the ISO intends to "drive LSEs into planning processes centered on the month-ahead." The ISO believes that a month-ahead planning horizon is appropriate as the minimum resource planning horizon for LSEs. In fact, the ISO supports a much longer planning horizon, either a year or longer. The ISO believes that a "spot-market focused" planning period is inappropriate, results in real-time operation problems for the ISO, and discourages long-term generation investment. Finally, contrary to CDWR's assertions, the ACAP requirement is directed at peak periods. As explained in the MD02 Filing, the ISO's proposed monthly ACAP obligation is based on the ISO's forecast peak load and duration. MD02 Filing, Appendix A at 61-64.

The CPUC/IAWG raises a number of jurisdictional issues. As noted above, the ISO believes that its ACAP proposal is fully consistent with, and necessary to support, its obligations and responsibilities – primarily that of reliable system operation. The ISO is not assuming a "resource procurement" role. The ISO recognizes and agrees that resource procurement issues are appropriately addressed and overseen by local regulatory authorities. The ISO believes that under its ACAP proposal, the state and other local regulatory authorities would still have complete discretion on many issues regarding legitimate state public policy (structure of a LSE's portfolio, LSE/statewide resource mix/fuel diversity, environmental impact, etc.). The primary purpose, and focus of, the ISO's proposed ACAP requirement is to support reliable system operation by encouraging LSEs to procure *an amount* of resources necessary to satisfy their load plus reserves. How an LSE goes about satisfying that requirement is a matter best left to, or overseen by, local regulatory authorities. Moreover, nothing in the ISO's proposal forecloses the development of a "statewide" planning reserve process and requirement comparable to that in place in New York, Texas and other jurisdictions. In fact, the ISO would celebrate such a development. However, at present, no such requirement or process exists and the ISO cannot wait until the necessary institutional and regulatory mechanisms are in place - the ISO's proposal is consistent with its mandate to ensure reliable system operation.

CMUA asserts that the ISO's ACAP proposal will lead to "broad, unfettered, and undefined control over resources by the ISO." CMUA at 19. Specifically, CMUA objects to the ISO's proposal to require ACAP resources to available to the ISO via a combination of firm forward energy schedules, bids to participate in unit commitment, supply ancillary services and energy markets, and must respond to ISO dispatch requirements. CMUA at 18-19. MID raises similar concerns. MID at 6-7.

The ISO respectfully disagrees. In fact, the ISO's proposal is designed to be minimally intrusive into a LSEs procurement decisions and activities. The ISO believes that it has proffered the minimum required set of rules necessary to support reliable system operation. As provided in the May 1 Filing, the ISO's daily ACAP obligation provides for LSEs to provide and schedule the ACAP resources necessary to satisfy their forecast load, plus reserves. As represented by the ISO, this approach would enable LSEs to shape their ACAP resources to satisfy their hourly load requirements for the next day. MD02 Filing, Appendix A at 64-65. What ACAP resources the LSE uses to satisfy its daily obligation is completely under the LSE's control. Thus, if an LSE has a portfolio of ACAP resources that includes base-loaded gas resources, hydroelectric resources, peakers, and firm energy contracts (tied to a specific resource), the

LSE can decide to schedule and commit only those resources necessary to satisfy its next-day load plus reserves and can use those resources as it sees fit.

For example, on any given day, it may decide, because of the terms of its arrangements, that it wants to schedule and use its firm energy contracts to satisfy its ACAP obligation, rather than its base-load resources. The LSE is free to make such decisions. The LSE is also free to self provide Ancillary Services and have the Ancillary Service capacity counted towards meeting its ACAP obligation. Indeed, as detailed in the May 1 Filing, the ISO specifically rejected an alternative daily ACAP obligation wherein LSEs would provide their entire ACAP portfolio to the ISO and the ISO would then determine which resources to commit to meet the next-day's load. The ISO concluded that such an approach was inconsistent with the ISO's objective of minimizing its role in the commitment process. MD02 Filing, Appendix A at 65.

The ISO believes that its ACAP proposal is completely compatible with the vertically integrated structure of CMUA's members and MID and does not in any way prohibit the "self-scheduling" of resources. Thus, contrary to CMUA's assertions, the ISO's proposal does not differ from the Eastern capacity markets and offers comparable "self-scheduling" opportunities and flexibility. Moreover, to the extent that LSEs self-schedule and self-commit sufficient resources to satisfy the next day's forecast load, plus reserves, the ISO will not be forced to take any action (i.e., commit and dispatch any resource) absent a significant change in forecast or system conditions (e.g., line outages, significant congestion, etc.).

The ISO agrees with the MSC's statement that, to be viable, a capacity requirement must precisely specify whether the ISO will curtail load and what LSE will be curtailed if there are insufficient resources (bids at or below the price cap) in real time. MSC at 2. The ISO proposes measures that are consistent with those principles. For example, as stated on page 66 of the MD02 Filing, one consequence of an LSE being ACAP-deficient in the month-ahead timeframe is that the LSE must submit an amount of "demand resources" necessary to make up the deficiency. That is, an LSE must offer to the ISO an amount of legitimately curtailable load that will be interrupted should reserves fall to a specific level. Such a requirement will ensure that each LSE is individually responsible for procuring sufficient ACAP resources and in instances where the ISO does not have sufficient resources to satisfy real-time load, ACAP-sufficient LSEs will be protected and ACAP-deficient LSEs will have their load curtailed. However, as noted in the MD02 Filing at page 67, the ISO is presently unable to target, or limit, load curtailments to individual LSEs (accept at the aggregate UDC level). Thus, it is imperative that the ISO, LSEs and local regulatory authorities work together between now and 2004 to ensure the development of such mechanisms.

CCSF raises a number of concerns with respect to the ISO's ACAP proposal. While CCSF states that it supports a requirement for LSEs to maintain sufficient capacity for reliability reasons, CCSF urges FERC to allow sufficient time for the development of an effective supply adequacy and procurement mechanism. CCSF at 9-10. CCSF states that the ISO's proposal will impose a new costly procurement obligation on LSEs and that the ISO has provided no information regarding the cost and operation impact of its proposal. CCSF states that the ISO's proposal inappropriately shifts costs and fails to address market power concerns. CCSF at 10. Moreover, CCSF states that the proposal is an inappropriate delegation of the ISO's procurement responsibilities with respect to Reliability Must-Run Generation. CCSF at 10. Palo Alto also asserts that the ISO's proposal is not consistent with the principle of cost-causation because it shifts local grid reliability costs from the control area operator to the LSEs. Palo Alto at 9-10.

CCSF and Palo Alto raises a number of very important issues. The cost-shifting and market power issues raised by CCSF and Palo Alto greatly influenced development of the ISO's final MD02 proposal. CCSF is correct that under the ISO's proposal, costs that are today borne by a greater portion of Load on the ISO Controlled Grid will, under the ISO's proposal, be assigned to the Load located within constrained areas of the grid. Within the context of its long-term market design proposal, the ISO believes that such an assignment of costs is consistent with the specific tenets of locational marginal pricing and, more broadly, cost-causation.

However, the ISO recognizes that its proposal raises certain legitimate equity issues with regard to cost-shifting and market power mitigation. CCSF is correct that Reliability Must-Run (RMR) costs that are today assigned to individual Participating TOs who then pass those costs along to all customers in their Service Area as well as users of the entire ISO Controlled Grid would, under the ISO's proposal, be assigned to Load-Serving Scheduling Coordinators whose Load is located within Local Reliability Areas (LRAs). MD02 Filing, Appendix A at 57-58. Moreover, CCSF is correct that, once again on a long-term basis, the ISO is proposing that existing RMR Generation requirements be phased out and that these responsibilities ultimately be borne by the Scheduling Coordinators representing Load in the RMR Area or LRA. MD02 Filing, Appendix A at 69-70. As a general matter, the ISO believes this approach to be consistent with cost-causation and accurate locational pricing. As noted in the MD02 Filing, the LRAs are defined by the transmission constraints that restrict the amount of power that can be imported into the area to serve load within the area. MD02 Filing, Appendix A at 57. Thus, as a result of these transmission constraints, prices within the area differ from those outside the LRA and are typically higher. Today, these price differences are not reflected in either the energy prices paid by end use load or at a wholesale level. As a result, the higher costs of serving load in these areas is socialized across the host UDC's Service Area. Under the ISO's MD02 proposal, the ISO is proposing to establish more accurate locational price signals, both by establishing an LMP-based energy/congestion management/ancillary services market, but also by requiring that local load procure the resources necessary to satisfy its demand and reserves – hence the locational ACAP requirement.

However, despite the ISO's goal to establish accurate locational pricing, the ISO has and does recognize the equity issues involved. In response to these concerns, the ISO tailored its ACAP proposal so as to mitigate the cost shifting impacts. First, the ISO proposes to defer the implementation of ACAP until 2004 in order to reduce the ability of ACAP suppliers to exercise market power by exacting high prices for ACAP capacity. MD02 Filing, Appendix A at 48. In addition, recognizing the equity and cost-shifting implications of phasing out RMR Generation and transferring cost-responsibility for local-area reliability issues to the LSEs in each LRA, the MD02 Filing provided for an extended phase-out of existing RMR arrangements until 2006. MD02 Filing, Appendix A at 51. The ISO believes that such a timetable will provide sufficient time for the negotiation of new arrangements between LSEs and local providers and, most importantly, the development, if necessary, of appropriate local market power mitigation instruments, including new and/or modified RMR contracts.

CCSF also raises concerns with respect to the use of FTRs for ensuring the deliverability of ACAP resources. CCSF states that there is no assurance that the ISO can offer an amount of FTRs necessary to support ACAP resources. CCSF at 11. As clarified in the ISO's MD02 tariff language filing, made concurrent with this filing, the ISO is no longer requiring LSEs to procure FTRs to deliver ACAP resources. As stated in its June 17 filing, the ISO proposes that a minimum level of ACAP must be procured from within the LRA (comparable to, and in order satisfy, the RMR requirements in the area), but the remainder of an LSEs ACAP requirement can be secured from any ACAP-qualified resource, with or without FTRs. Thus, it is not necessary to procure FTRs in order to deliver ACAP. Rather, an LSE may wish to procure FTRs in order to hedge the risk of congestion costs when scheduling the delivery of energy from an ACAP resource. The ISO believes that this modification to the MD02 Filing will address CCSF's concern.

Santa Clara opposes the ACAP requirement because it asserts that the requirement to make unused capacity available to the ISO is, in effect a substantial and inappropriate increase in operating reserve. Santa Clara at 8. The ISO believes that Santa Clara misunderstands the concept behind, and details of, the ISO's proposed ACAP requirement. First, contrary to Santa Clara's assertion, the ACAP obligation is designed to capture the benefits of reserve sharing – not result in increased and unnecessary reserves. As provided for on pages 59-60 of the MD02 Filing, the ISO proposes to establish each LSE's monthly ACAP Obligation by determining a LSE's historical contribution to the ISO's peak load for that month. Thus, by examining a LSE's contribution to the coincident peak load, the ISO is considering, and factoring in, the diversity that exists on the system and capturing the benefit of reserve sharing.

SCE states that the focus of this proceeding and effort should be on the development of a short-term capacity obligation. SCE states that the issue and development of a long-term capacity obligation should be addressed by the CPUC in its procurement proceeding. SCE at 8-9. As noted earlier, the ISO believes that its proposed ACAP Obligation will not conflict with, or be redundant to, the procurement requirements ultimately established by the CPUC. First, the CPUC rules will only apply to a portion of the LSEs that use the ISO Controlled Grid. Therefore, it is appropriate for the ISO to establish rules that apply to all LSEs that use the ISO Controlled Grid. SCE appears t agree with that approach.

SCE at 11. Second, the ISO believes that it is appropriate and necessary for the ISO to establish mechanisms that support reliable system operation. The ISO does not believe that by establishing the ACAP requirement proposed in the May 1 filing, the ISO will inappropriately interfere with any of the procurement rules ultimately established by the CPUC for CPUC-jurisdictional LSEs. Moreover, the ISO believes that its proposed requirements are the *minimum* requirements necessary to support reliable grid operation – a matter over which the ISO has clear statutory responsibilities. The CPUC can always establish and impose general procurement and planning obligations on the state's investor-owned utilities that are more stringent than those established by the ISO.

SCE also raises concern that the ISO's proposal will inappropriately apply to LSEs that serve retail load served by on-site generation. SCE asserts that in no case can the ISO apply the ACAP Obligation to LSEs on a gross-load basis. SCE states that, if applied at all, the requirement must be applied on a net load basis. SCE at 10-11. The ISO respectfully disagrees. The ISO believes that its proposed ACAP Obligation is appropriately assigned to LSEs on a gross load basis, since the ISO's operating requirements are established, and driven, by the aggregate or gross load requirements of the system. Regardless of the net load requirements of individual LSEs, the ISO must stand ready to satisfy the gross load requirements of the system. In particular, the ISO's WECC-established operating reserve requirements are applicable to the ISO's gross load requirements. Thus, the proposed ACAP obligation – which is designed to support reliable system operation – should also be based on the gross load requirements of the system.

The ISO agrees with SCE that the ACAP Obligation should apply to all LSEs that use the ISO Controlled Grid and reside within the ISO Control Area. Such an approach is consistent with the application of comparable requirements in the Eastern ISOs. The ISO also agrees with SCE that rules must be adopted that detail the responsibility for meeting the capacity obligation associated with direct access customers and self-served customers. SCE at 12. While the ISO has not specified those details in its MD02 Filing, the ISO recognizes that such provisions must be developed.

SCE also states that the ISO and CPUC should comparable capacity obligations. In addition, SCE states that the ACAP proposal must recognize that the IOUs will not and cannot maintain reliability at any cost in order to meet their ACAP Obligation. The ISO agrees with SCE that the ISO's and CPUC's rules should not be in direct conflict. However, as stated above, the ISO believes that there is, and can be, a clear delineation of function between the two entities. The ISO should specify the level of capacity necessary to support reliable system operation and the CPUC should specify the procurement rules for the IOUs in satisfying that obligation. The ISO also agrees that LSEs should be given the discretion (and responsibility) to specify the price at which they value reliability. The ISO's proposal fully supports that notion – to the extent a LSE determines that the price of ACAP is too high, that LSE can either provide an amount of demand bids (price triggered) necessary to satisfy its ACAP Obligation or can provide an amount of demand resources (reserve triggered) sufficient to satisfy its obligation. Of course, the ISO hopes that LSEs do not avail themselves of the latter option frequently, as the price/cost and consumer impact may be enormous. However, this decision is best addressed by state regulators and legislators as a matter of fundamental state public policy.

The ISO also agrees with SCE that the ACAP Obligation should not dictate the mix of resources in each LSE's supply portfolio, only the magnitude of resources required. As explained above, the ISO's proposal does not attempt to pre-determine the portfolio or mix of resources necessary to satisfy the ACAP Obligation. The ISO believes that such decisions are best left to the individual LSE and their local regulatory authority. Similarly, the ISO largely agrees with SCE that the ISO's control over ACAP resources should be limited to the purpose for which the resource was acquired by the LSE (e.g., energy production, ancillary services production, etc.). The ISO's ACAP proposal is consistent with that concept – to the extent that a LSE has secured an ACAP resource primarily to provide ancillary services, there is nothing in the ISO's proposal that would prohibit that LSE from scheduling that resource in order to self-provide its AS requirements or from bidding that resource as AS into the ISO's market.

The ISO also agrees with SCE that the Commission should view the ACAP Obligation as a substitute for appropriate market power mitigation. SCE at 14. As the CA ISO recognized in its MD02 Filing, the ACAP Obligation itself will require close scrutiny and continual re-evaluation by both the ISO and the

Commission. In addition, because the ISO is not proposing to facilitate a formal capacity market itself, but instead require LSE to procure, on the open bilateral market, the resources necessary to satisfy the obligation, the ISO recommends that the Commission closely monitor the performance of the bilateral capacity market and assess whether the prices paid by LSEs in that market are just and reasonable. MD02 Filing, Appendix A at 52. The ISO is also concerned that suppliers may elect not to offer available capacity to LSEs in order to increase the market price. This concern is, in part, currently mitigated by the Commission's existing Must-Offer requirement. In the future, it may also be mitigated by the continuing existence of appropriate price mitigation in the ISO's spot markets. However, should this problem (withholding capacity) occur, the Commission may want to consider requiring suppliers to offer all available (i.e., not otherwise committed) capacity to LSEs and establishing price benchmarks for that capacity.[61] The Commission previously provided such benchmarks in December 15, 2000, order regarding the California electricity crisis. December 15 Order at 61, 994-995.

SCE contends that the ISO's locational ACAP proposal unnecessarily limits a LSEs options for acquiring capacity and places the LSE in a position to negotiate with a supplier that has locational market power. First, as stated above, the ISO believes that the locational ACAP requirement is consistent with at least the approach adopted under the NY ISO Tariff. See NYISO Installed Capacity manual, Section 2.6. The NY ISO Tariff basically provides that the NY

[61] The ISO notes that Reliant, in its separately filed motion to establish a capacity market

ISO establish “Transmission Districts” and that the NY ISO can specify specific capacity requirements for these districts. By definition, these transmission districts reflect areas into which there are significant transmission constraints, such as Long Island. Second, as noted above in response to similar concerns raised by CCSF, the ISO believes that its proposal to defer implementation of ACAP until 2004, combined with its proposed longer-term phase-out of RMR Generation (until 2006), significantly mitigates the ability of suppliers to exercise market power. Moreover, as recognized in the ISO’s May 1 Filing, certain suppliers may continue to possess locational market power in the future and appropriate mitigation, including cost-based RMR-type contracts, may still be needed and should be in place. MD02 Filing, Appendix A at 52, 69-70. Finally, the ISO made a commitment in the MD02 Filing to proactively identify and, if appropriate, mitigate or eliminate the transmission constraints that give rise to the ability of suppliers to exercise local market power. MD02 Filing, Appendix A at 48-51. The ISO believes that is a necessary and appropriate function and responsibility for the ISO to assume. SCE also states that the deliverability requirement should be modeled after the PJM approach where resource deliverability is addressed through the adoption of an interconnection policy that ensures deliverability for new resources that want to be ACAP resources. SCE at 15. The ISO agrees that such an approach has merit and so stated in the May 1 Filing. MD02 Filing, Appendix A at 75. However, while the ISO believes such an approach can work prospectively, the ISO continues to believes that a locaional ACAP requirement is necessary at present in for the foreseeable future.

As the ISO noted in its MD02 Filing, the ISO is committed to proactively eliminating, when appropriate, the transmission constraints that give rise to local generation requirements and reduce the deliverability of resources. MD02 Filing, Appendix A at 48-51.

Finally, SCE raises a number of other issues with respect to the ACAP proposal. SCE states that the Commission should permit existing supply contracts to qualify and be counted towards meeting the ACAP obligation and that ISO control over these resources be limited to the performance provisions of the contracts. SCE 17-19. In addition, SCE requests that the Commission authorize LSEs to pass through to suppliers any non-performance penalties incurred by a LSE. Finally, SCE requests that penalties be assessed on a net portfolio basis instead of a contract resource-specific basis.

As stated in the MD02 Filing, the ISO is clearly cognizant of the need for and desire of LSEs to be able to continue to rely on existing contractual arrangements to satisfy the ACAP Obligation. MD02 Filing, Appendix A at 77. Moreover, the ISO recognizes that the terms and conditions of these contracts are binding on the parties and should be accommodated to the greatest extent possible when evaluated for purposes of satisfying the ACAP obligation. Id. Indeed, the ISO Governing Board directed management to recognize the validity, for purposes of satisfying the ACAP Obligation, all contracts previously entered into by the state (i.e., all contracts entered into by California Energy Resource Scheduling or CERS). In most cases, the ISO believes that existing contracts, utility retained generation, and qualifying facility contracts will qualify as ACAP.

The ISO is committed to working with the parties to these existing contracts to ensure their availability as ACAP resources. Finally, the ISO agrees with SCE that LSEs should be able to incorporate in their ACAP contracts with suppliers appropriate penalties for non-performance by the supplier. MD02 Filing, Appendix A at 69.

Sempra recommends that the Commission defer consideration of a capacity requirement and consider the pros and cons of such a requirement in its SMD rulemaking process. While the ISO supports continued and further evaluation of capacity requirements in the context of the SMD rulemaking process, and will obviously conform to the standards adopted therein, the ISO disagrees with Sempra that the Commission should defer consideration of the ACAP proposal. While the ISO recognizes that the ACAP proposal is likely to evolve over time, the ISO believes that it is imperative that the Commission quickly establish the rules and obligation for ensuring long-term generation adequacy in the California market. Should the Commission defer consideration of the ACAP proposal, the ISO is concerned that the benefits of a deferred implementation (namely, the mitigation of supplier market power) will be lost. That is, if the Commission does not now clarify the rules and obligations to be placed on LSEs in the California market, LSEs will be unable to begin to negotiate firm supply arrangements for 2004 and may be forced, at a later date, to accept higher-priced offers from suppliers who know that LSEs have little option to accept the offer or face a high deficiency charge. By negotiating far in advance of the commitment period, a LSE can mitigate a supplier's market power, since the LSE will presumably have more options available to it to satisfy the capacity obligation (e.g., multiple suppliers, building generation, facilitating demand response, etc.). The Commission should act now on the ISO's proposed ACAP Obligation.

SMUD generally supports the ACAP proposal. SMUD states that LSEs that have properly procured capacity should be the last to be curtailed. SMUD also suggest tariff language to make clear that ACAP obligations are firm commitments. The ISO agrees with SMUD that the load of ACAP-sufficient LSEs should be curtailed after the load of ACAP-deficient LSEs and that ACAP obligations are form obligations. The ISO proposal is consistent with those concepts.

Strategic contends that the ISO has not explained the need for its proposed ACAP Obligation nor the reason why existing mechanisms (Replacement Reserves) are insufficient. Moreover, Strategic contends that ACAP addresses long-term capacity while the problem in California is short-term supply. Strategic states that Energy Service Providers (ESPs) in California have no obligation to serve and should be exempt from ACAP. Strategic states that if such exemption is denied, existing contracts between ESPs and their retail customers should be grandfathered and that ACAP should be implemented no earlier than the date the full locational model is implemented. Finally, Strategic states that the Commission should greatly simplify the ACAP proposal and that monitoring and enforcement should be overseen by an independent third party, possibly the WECC.

The ISO disagrees that the problem in California is only short-term supply and not long-term capacity adequacy. In fact, the ISO believes that the existing supply-demand imbalance was the result of an ambiguous obligation to serve and the lack of rules and tolls necessary for long-term investment. Thus, it is critical that the ISO and the Commission provide a platform for long-term investment and the ACAP is such a platform. For too long LSEs in the state have relied upon the spot market as a resource to satisfy load. At this juncture, it is critical that LSEs begin to plan and conduct a long-term procurement strategy to ensure supply adequacy in the state. Such steps are necessary if the ISO to be able to maintain system reliability.

L. The Conceptual Objections to the ISO's FTR Proposal are Without Merit

1. Existing Transmission Contracts Will Not Be Converted To FTRs That Are Obligations

Most of the intervenors that have addressed the issue support the ISO's proposal to implement firm transmission rights (FTRs) that are "obligations." SWP and the City of Santa Clara express concerns about FTR Obligations Santa Clara at 18; SWR at 12. Santa Clara argues that Existing Transmission Contracts (ETCs) converting to FTRs should not be forced to take FTR Obligations. Santa Clara at 18.

All other ISOs that use the LMP congestion management model have FTR Obligations. SMD Working Paper at 11. The SMD Working Paper takes the position that transmission providers must initially offer source-to-sink FTR obligations, and must offer source-to-sink FTR Options as soon as it is technically feasible. *Id*. Consistent with the SMD Working Paper, the ISO proposes to offer FTR Obligations upon implementing LMP based on the Full Network Model in Phase 3 of MD02, and is exploring the feasibility of offering FTR Options. MD02 Filing, Attachment A at 91. In addition, however, the ISO proposes a special provision to allow ETC holders that convert to FTRs to receive FTR Options if they so desire. Although this provision complicates the release of FTRs under MD02 by requiring a distinct allocation procedure and creating two different “flavors” of FTRs, the ISO recognizes the value of this provision in encouraging ETC holders to convert to FTRs, and has determined that it will be technically feasible. Thus SWP’s and Santa Clara’s comments reflect a misunderstanding of the ISO’s proposal with respect to ETCs that convert to FTRs. ETCs that convert to FTRs will have the choice of receiving FTR Options or FTR Obligations. This is consistent with the position enunciated in the SMD Working Paper that “existing firm point-to-point transmission contracts are similar to transmission rights that are options. SMD Working Paper at 11. Thus, Santa Clara’s and SWP’s concerns are unwarranted.

2. The ISO Recommends That The Commission Require ETCs To Schedule Service On The Same Timeline As OATT Customers And Convert to FTRs Upon Their Termination

Mirant suggests that the Commission should order the conversion of ETCs to FTR in five years. Mirant at 43. As the ISO has recognized on many occasions, ETCs have created many challenges to the ISO and resulted frequently in “phantom” congestion.[62] The ISO would like to see all market participants receive service under a common transmission tariff. Such an outcome is imperative if the ISO’s congestion management protocols are to produce meaningful, effective results. In particular, the efficiency of the LMP congestion management approach proposed in the MD02 Filing depends on having consistent transmission allocation and pricing rules in the forward and real-time markets. Unfortunately, the requirement to serve two completely different classes of grid users –one served under the OATT and the other served under ETCs – according to different transmission allocation and pricing rules and on different scheduling timelines, undermines the LMP design.[63]

The ISO, as required by the Commission, will continue to honor all ETCs. Termination of all ETCs by a date certain, as proposed by Mirant is arbitrary and will likely be problematic. However, the ISO recommends that the Commission not permit transmission owners to renew ETCs as such ETCs expire under their own termination provisions. This approach would be consistent with the

62 Under both the ISO’s existing congestion management system and that proposed in the MD02 Filing, the requirement to honor ETCs means that the ISO must first subtract all ETC capacity, whether actually scheduled or not, from the transmission capacity that is available to market participants. Consequently, market participants may be curtailed and/or charged (in the day-ahead and hour-ahead markets) for congestion that will not materialize in real time. In many instances, much of this reserved ETC capacity has gone unused, yet other market participants have had their preferred schedules curtailed and have been charged for what turns out to be phantom (i.e., not real) congestion. This clearly distorts the forward congestion management market and impedes the efficient allocation of transmission capacity. This sub-optimal result likely will be exacerbated under a nodal congestion management pricing model, since the procedure for reserving ETC capacity will have to ensure the simultaneous feasibility of ETC capacity reservations.

63 For example, under the LMP design a party who under-schedules load in day-ahead in order to limit exposure to day-ahead congestion charges, should face an appropriate risk of real-time congestion charges when the un-scheduled load appears. When there is phantom congestion, however, additional transmission capacity becomes available in real time, thus reducing the risk to under-scheduled load and undermining the LMP incentive structure that is supposed to discourage inefficient arbitrage.

Commission's actions in the natural gas industry with respect to individually certificated, Part 157 services that essentially are the natural gas industry's equivalent of ETCs. Specifically, the Commission ruled that conversion to openaccess, Part 284 transportation service was appropriate for shippers whose contracts for individually certificated, Part 157 service expire/terminate. *See Transcontinental Gas Pipeline Corporation*, 60 FERC ¶ 61,119 (1992). Likewise, ETCs should be converted to service under the OATT upon their expiration.

The ISO believes that the more urgent issue, particularly from the viewpoint of inter-control area coordination of congestion management, is to require all grid users, both those with ETCs and those scheduling transmission service under the OATT, to schedule their transmission service on the same scheduling service timeline. Specifically, any ETC capacity that is not scheduled in the day-ahead market should be made available to accommodate the day-ahead and hour-ahead schedules of other grid users. Although this step would not eliminate the need to reserve capacity for ETCs in the day-ahead market, it will relieve the ISO of having to continue to reserve unscheduled ETC capacity in the day-ahead and hour-ahead markets, and thus will eliminate phantom congestion. Accordingly, the ISO submits that it is necessary that the Commission require ETCs be required to conform to the standard scheduling timeline applicable to all transmission users.

3. It Is Appropriate to Allocate FTRs to LSEs

Mirant and IEP request that the Commission reject the ISO's proposal to allocate FTRs to LSEs and, instead, require the ISO to auction off all FTRs and allocate the revenues to LSEs. Mirant at 42-43; IEP at 20. Mirant claims that the ISO's proposal would leave virtually no transmission capacity available for new market entrants and suppliers regardless of how they value transmission rights. Mirant at 42. IEP claims that an auction open to all market participants can determine the appropriate value of FTRs and their most economically efficient allocation. IEP at 20.

In reality, IEP's and Mirant's proposal exalts form over substance. Mirant acknowledges in its protest that any LSE that desires to maintain its rights could bid an arbitrarily high price for the FTRs and retain their full value because all of the revenues from the auction sale would return to the LSE, *i.e*. LSEs would essentially be paying themselves. Mirant at 42. There is no reason to expect that LSEs would behave any differently. Mirant's and IEP's proposal would merely impose an additional administrative burden on the ISO and auction participants.

Further, Mirant's and IEP's protests reflect a fundamental misunderstanding of the ISO's proposal. Under the MD02 Filing, FTRs follow load not LSEs.[64] MD02 filing, Attachment A at 91, 96. If a load should switch from its existing LSE to a new supplier, then the associated FTRs would be shifted to the new supplier. Moreover, the ISO will allocate FTRs to LSEs only in the quantities necessary to serve their load, net of local generation, based on historical patterns of load and grid usage. Based on the ISO's proposed allocation rules, there should be additional transmission capacity available in the

[64] The ISO will initially allocate FTRs to LSEs based on historic quantities and geographic distribution of their loads and supply resources as is done in PJM. MD02 Filing, Attachment A at 91.

FTR Auctions. Finally, new market entrants and the other suppliers will be able to obtain FTRs in the FTR Secondary Market. *Id* at 99. Thus, there are ample opportunities for new suppliers to obtain FTRs.

Conceptually, the ISO believes that the use of the transmission system by existing customers, *i.e.*, native load, must be recognized in any transition to a new standardized market design. Native load should be entitled to transmission rights and be able to retain possession of such rights regardless of which LSE or wholesale transmission customer schedules power delivery on the load's behalf. To facilitate retail competition, such rights would move with the load to whomever the load select as its LSE. The allocation approach the ISO has proposed comes closest to preserving the rights that customers have prior to the new market design. Although the auction option proposed by IEP and Mirant would allow customers to value transmission based on need, the ISO's proposal is more appealing in California given the diversity of loads and LSEs that use the ISO control area. Many ISO system users seem to prefer a FTR allocation scheme in which their needed transmission rights are allocated prior to any auction, thereby eliminating the need for auction participation. Further, as indicated above, the ISO's proposal does not discourage the participation of new supplies because it would permit load to retain transmission rights if it chooses new suppliers.

4. The Scheduling Priority Should Be Retained for FTRs

In the MD02 Filing, the ISO proposes to retain its existing day-ahead scheduling priority for point-to-point FTR holders. MD02 Filing, Attachment A at 90. Specifically, under Section 9.7.1 of the ISO Tariff, point-to-point FTR holders have a scheduling priority in the day-ahead market, which means that balanced schedules submitted in the day-ahead market with the appropriate point-to-point FTRs associated will have priority against curtailment over other non-ETC schedules. This priority does not extend beyond day-ahead, however, so that FTRs not used with preferred schedules in the day-ahead market for any hour have no scheduling priority in the hour ahead market or in real time. IEP suggests that the ISO should make its FTRs purely financial instruments with no scheduling priority. IEP at 21.

The ISO submits that FTR holders should retain their scheduling priority. The impact of the ISO's proposed scheduling priority is quite minimal, since it only provides a tie-breaker mechanism for those situations where submitted bids are insufficient to manage congestion. Under MD02's integrated energy and congestion management approach, the same bids will be used for energy trading and for congestion management, and therefore the problem of insufficient bids – and hence the frequency of instances where scheduling priority is invoked – should be minimal. Finally, the scheduling priority has been approved by the Commission and is generally accepted by market participants in California.[65]

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[65] In its Order accepting the ISO's existing FTR scheme, the Commission rejected arguments that the scheduling priority should be eliminated. *California Independent System Operator Corporation*, 87 FERC ¶ 61,143 at 61,573 (1999). In particular, the Commission rejected arguments that the scheduling priority would reduce the incentive of FTR holders to submit adjustment bids and reduce the ISO's ability to manage congestion. *Id.* The Commission noted that the scheduling priority does not affect the congestion management situation in any significant way because it merely serves as a tie breaker when there are not price differentials in the Adjustment Bids or when there are insufficient Adjustment Bids. The MD02 proposal does not alter this concept of scheduling priority. Consistent with its prior decision, the Commission should reject IEP's proposal to eliminate the scheduling priority.

5. Three-Year FTRs Are Appropriate

The CPUC/IAWG submit that the ISO is proposing to auction off a significant share of capacity (30 percent) as three-year FTRs. CPUC/IAWG claims that longer-term FTRs should not be implemented until California markets stabilize. CPUC/IAWG at 26.

The ISO submits that issuing three-year FTRs at this time is appropriate and respectfully disagrees with CPUC/IAWG that the ISO is issuing an excessive amount of three-year FTRs. There is a legitimate need for transmission certainty over a longer period of time. As the Commission is well aware, since the ISO first proposed FTRs numerous market participants have complained about the one-year FTR limitation and indicated that such FTRs are not an adequate substitute for the long-term services offered under the Tariff. In approving one-year FTRs for the ISO, the Commission stated that such proposal was "acceptable initially", but the Commission directed the ISO to use its experience with the first FTR offering to develop a proposal that would provide for long-term FTRs. *California Independent System Operator Corporation*, 87 FERC ¶61,143 at 61,572 (1999). The ISO's proposal to issue a moderate amount of three-year FTRs is intended to comply with the Commission's directive and address a legitimate need of market participants. As the Commission recognized in its Order approving the ISO's initial FTR offering, a mechanism to obtain long-term transmission rights is important for the development of a competitive and efficient electricity market in California. *Id*. Reducing congestion risk is important in light of the large amounts of capital involved in potential future investments by market participants. The

Commission expressed concern that the absence of firm transmission service of any significant term disadvantages the bilateral transmission market. *Id*. The ISO's proposal addresses the Commission's stated concerns about long-term commitments. At the same time, the ISO believes that its proposal addresses CPUC/IAWG's concern about current uncertainties in the California markets by issuing only a modest quantity of long-term FTRs (i.e., 30 percent of available transmission capacity, after reserving capacity for ETCs).

M. LMP Implementation Issues

Intervenors raise a hodge-podge of arguments regarding the ISO's proposal to implement a LMP pricing and congestion management scheme. The Sacramento Municipal Utility District (SMUD) believes that LMP may be inappropriate for California. SMUD at 20-23. The California Municipal Utilities Association (CMUA) and Transmission Agency of Northern California (TANC) suggest that more analysis of LMP is needed before it is implemented, and TANC suggests a five-year or longer transition period. CMUA at 21-23; TANC at 9. On the other hand, the Electric Power Supply Association (EPSA) urges the Commission to require the ISO to accelerate the implementation of the LMP. EPSA at 24. Several parties express concerns about the impact of LMP on loads. In particular, these interveners appear to be concerned that LMP will cause prices to increase in certain load pockets. City of Palo Alto at 6-8; City and County of San Francisco at 12-5; City of Santa Clara at 12-15. The City and

County of San Francisco recommend that load pay LMP prices that are aggregated at the level of the major transmission owners (PG&E, SCE and SDG&E). San Francisco 17-18.

LMP has been implemented successfully in the eastern ISOs, and no intervener disputes that fact. Further, the Commission's SMD Working Paper concludes that transmission providers should manage congestion using LMP and implement nodal pricing for both buyers and sellers. SMD Working Paper at 7, 16, 18. The ISO agrees that the LMP approach provides the most accurate way to perform forward congestion management, and that it eliminates the well-known problems of infeasible schedules and the "Dec Game" that have plagued the ISO markets since start-up and are rooted in the inter-zonal versus intra-zonal distinction. No intervener raises any plausible reason why LMP will not work in California.

Implementation of LMP and the full network model will require extensive software and systems development. The ISO anticipates that it will take 12 months from the date of a Commission order approving the ISO's market design to have the necessary systems in place. Further, the ISO will need to undertake the proper testing of the systems, conduct test runs and work with market participants to clarify how the LMP scheme will work and the prices LMP might produce in actual operation. The ISO believes that it will need six months of testing[66] for all market participants to be "comfortable" with the results that a LMP

[66] The six months of testing with market participation will partially overlap the 12 months of system development, so that the new design can go into operation in fourth quarter 2003.

scheme will produce.[67] Prior to being able to produce LMP results for actual operation, the ISO will conduct a thoroughly empirical pricing analysis.

The ISO is surprised that certain interveners would have the ISO rush to implement a new market design without the proper testing and analysis. The ISO's existing market design has not functioned well. The ISO seeks to avoid the mistakes of the past and the problems that likely would follow from a hurried implementation of LMP. IEP too agrees that rushing to implement a new market design threatens to repeat the mistakes of the past. IEP at 5. The ISO notes that it took New York approximately two years to implement nodal pricing. The ISO's timetable is quite reasonable in comparison, especially given the extent of prior market design related problems in California following the break-neck implementation timetable leading to ISO start-up.

On the other hand, there is no reason to wait several years to implement LMP. LMP has been implemented successfully in other ISOs, and there is no reason LMP cannot be implemented successfully in California. Given the weaknesses of the current market design, it is imperative that the new market design be implemented without further delay once it has been thoroughly tested with California-specific data, all the kinks have been worked out and market participants are comfortable with the operation and results of the design.

[67] In late 2002, the ISO intends to have a network model developed on its EMS system that incorporates detailed representations of PG & E's , SCE's and SDG & E's transmission systems. With that model in place, the ISO expects to be ready to perform the State Estimator solution. The ISO expects it will be some time in the first quarter of 2003 that the EMS State Estimator solution will be tested and tuned to the point the ISO can begin producing LMPs that represent actual operational conditions.

The question of how to settle loads under LMP is the more substantive issue, but it can be addressed separately from the decision to implement LMP for congestion management. In its MD02 Proposal, the ISO proposes initially to schedule and settle loads at the Demand Zone Level and, when technically feasible, at the Load Group Level.[68] MD02 Filing, Attachment A at 120. Several interveners express anxiety that LMP pricing will have a significant cost impact on them. The ISO recognizes the equity concerns of these interveners[69] and is willing to accommodate such concerns. The ISO's design is flexible and capable of scheduling and pricing loads at any appropriate load aggregation level. The ISO notes that PJM and the NYISO settle loads at the utility level.[70] However, the SMD Working Paper (pp. 16, 18) contemplates nodal pricing for loads in both the day-ahead and real time markets. The ISO's proposal for pricing loads falls in the middle of these two extremes. It might be appropriate to phase-in more granular pricing of loads. As the ISO indicated in the MD02 Filing, sending strong locational price signals to market participants can help promote investment in transmission, new generation, forward contracting and demand responsiveness. On the other hand, locational pricing could have severe cost impacts on consumers in congested areas due to constraints in a transmission system that was designed and constructed under a different regulatory regime. Transmission upgrades are needed in certain portions of the ISO grid to enable

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68 There are approximately 20 Demand Zones in the ISO Control Area and over 40 Load Groups. *See* MD02 Filing, Attachment A at 124.

69 In the MD02 Filing, the ISO recognized that LMP could have significant cost impacts depending on the geographic granularity of load scheduling and settlement. MD02 Filing, Attachment A at 119.

70 Nothing in the ISO's proposal would preclude the CPUC from setting retail rates at the utility level.

consumers in those areas to benefit fully from competition. Accordingly, some transition period will likely be necessary before the ISO's LMP implementation settles loads on a highly granular basis.

N. MARKET-RELATED ISSUES

1. 10- Minute Markets

Bonneville and Duke urge the Commission to eliminate the ISO's 10-minute market. Bonneville at 8-9; Duke at 7-8. The ISO's MD02 Filing retains the Commission- approved 10-minute market. *See California Independent System Operator Corporation*, 91 FERC ¶61,324 (2000). The ISO implemented a 10-minute market because its prior settlement scheme led to inefficient and unintended operational consequences including: (1) inefficient price signals that resulted in the ISO's inability to rely on Imbalance Energy for load following which in turn led to excessive use of Regulation service; (2) decreased incentive for scheduling coordinators to submit bids in the Imbalance Energy market; (3) a "stuck" hourly price for Incremental Energy imports; and (4) extremely poor compliance with ISO dispatch instructions. *Id.* at 62,113. Since the 10-minute market has been established, there have been many discussions on the continued need for and effectiveness of the 10-minute market. The discussion will undoubtedly continue and the ISO will continue to examine the 10-minute market.

2. The Hourly Market

CAC asserts that is unduly discriminatory for the ISO to pre-dispatch supplies from outside of the ISO Control Area for a full hour, while in-state resources are only dispatched for ten-minute intervals. CAC at 5. Dynegy also supports an hourly market in which in-state and out-of-state supplies are treated on a purportedly equal footing. Dynegy at 25-26.

CAC and Dynegy fail to realize that imports and in-state generation are not similarly situated. There are no Ancillary Services requirements associated with imports because they are delivered from another control area. The other control area assumes responsibility for delivery of imported electricity. Imports are deemed delivered; whereas, in-state generation can deviate. However, the ISO is open to discussing hourly market issues in the upcoming stakeholder process.

3. Real Time Economic Dispatch

Dynegy alleges that the ISO "apparently is using its target price methodology as an excuse to attempt to lower prices in its imbalance energy market." Dynegy at 33. But in the very next sentence in its protest, Dynegy says "[a]t least that is what Dynegy suspects the CAISO is doing." *Id*. However, Dynegy claims there is "simply no way to understand this *dense* proposal" and the "CAISO Staff rejected a proposal to have further discussions*." Id.*

More than 40 interventions were filed in this proceeding. Dynegy is the only intervenor that protests the ISO's Real Time Economic Dispatch/Target Price proposal. In particular, no other generator or generator trade association objects to the ISO's proposal to eliminate the troublesome Target Price mechanism. Indeed, two generators -- Duke and Williams -- expressly support the ISO's Real Time Economic Dispatch/Target Price proposal. Duke at 18; Williams at 27. Moreover, no other intervenor expresses confusion about the ISO's proposal.

Dynegy acknowledges in its protest that the ISO has been discussing the Target Price issue with stakeholders for some time now. Dynegy at 33. In connection with the Target Price proposal in Amendment No. 42, the ISO held four stakeholder outreach sessions and made a number of significant changes to its proposal as a result of these stakeholder discussions. Dynegy staff participated in at least some if not all of the stakeholder sessions. Dynegy also claims that the issue was raised at the Commission-sponsored technical conference, and the ISO staff has not discussed the issue. A review of the ISO's notes from the Commission-sponsored technical conference in San Francisco on April 11, 2002 shows that Dynegy raised the issue of how the Target Price proposal would work. These notes reflect that Mark Rothleder of the ISO went through examples of the Target Price proposal. The notes from the technical conference do not show that any party sought further explanation of the proposal from the ISO after Mr. Rothleder's explanation of the concept. However, to clarify the matter for Dynegy, Attachment D hereto provides an example of the Target Price proposal.

The ISO's Target Price proposal is discussed in greater detail in the Affidavit of Mark Rothleder that is Attachment O to the MD02 May 1 Filing. Dynegy does not acknowledge let alone address the discussion in Mr.

Rothleder's Affidavit. Dynegy's claim that the Target Price methodology is simply an "excuse" to lower prices in the Imbalance Energy market is inane. The ISO's Target Price proposal addresses the price overlap issue that has invited manipulation and caused inefficiencies and perverse price signals in the ISO's markets since it was first implemented. The price overlap is an unpredictable quantity of bids from Scheduling Coordinators (SCs) willing to reduce generator output (buy real-time energy) at prices higher than the prices at which other SCs are willing to increase generator output (sell real-time energy). Thus, in a market with real time trading opportunities, overlapping bids are essentially mutually beneficial trades between buyers and sellers, and the price overlap is eliminated. Attachment O at 3. Under the ISO's existing market design there is no opportunity for SCs to execute such trades or for the ISO to execute such trades on their behalf. Thus, the ISO's Target Price proposal provides economic efficiency, provides price signals consistent with the ISO's imbalance requirements, and minimizes the opportunities for market manipulation. In other words, the Target Price Proposal is a win-win situation for all market participants. That must explain why all of the interveners that understand the ISO's proposal either expressly support it or do not oppose it.

4. Single Energy Bid Curve

Reliant and Williams oppose the use of a single energy bid curve. Reliant at 25; Williams at 27. Reliant states that, to be able to offer all energy into the market and provide back-up to bilateral commitments, a generator must be able to change its energy bid up to an hour before real time to reflect risks and opportunity costs that may appear in the interim. Reliant at 25. Williams argues that the ISO needs to accommodate flexibility in the event circumstances changes between the close of day-ahead market and hour-ahead market. Williams at 27-28.

Interestingly, no other generators oppose the ISO's proposal for a single energy bid curve and Duke expressly "supports the use of a single bid curve." Duke at 18. Under the ISO's proposal, the portion of the energy bid curve associated with capacity selected in the day-ahead market and the RUC process cannot be increased in a subsequent market. However, participants are free to revise the portion of their energy curve associated with capacity not selected in the day-ahead market and the RUC process so long as such revisions maintain a monotonically increasing energy bid curve for the unit's entire output range. MD02 May 1 Filing, Attachment A at 112; Attachment H at Section 5.13.2.2. Logically this approach is analogous to the basic tenet of contract law that an accepted offer is a contract. If the ISO is relying on an energy bid to serve scheduled load and operate the grid reliably, suppliers should not be permitted to change bids without a valid reason, thereby forcing the ISO to scramble to meet its obligations and maintain operational integrity of the transmission system. The ISO's proposal still permits a fair amount of flexibility for suppliers. For example, in the day-ahead market, suppliers are permitted to submit different bids for different hours of the day. Further, any capacity that has been bid, but not accepted by the ISO, can be re-bid into the ISO's markets. Finally, suppliers are allowed to reduce their bid energy prices, even for capacity that has already been accepted, if they wish to increase the likelihood of the associated resources being dispatched by the ISO.

O. Demand Responsiveness

Dynegy claims that nothing in the ISO's MD02 Filing addresses demand responsiveness and urges the Commission to order the ISO to implement demand response programs. Dynegy at 6. The ISO is proposing to expand the flexibility for loads to participate in its market-based program, the Participating Load Program (PLP). Consistent with the SMD Working Paper, the MD02 proposal accommodates demand-side bidding, including the option to submit multi-part bids in the day-ahead, hour-ahead and real time markets. MD02 Filing, Attachment A at 112, 125. Similarly, load will be able to participate in the RUC market, and ACAP obligations can be satisfied by load reduction bids. MD02 Filing, Attachments A at 47, 72, 74. The ISO has initiated a round of discussions with PLP participants to enhance their participation in 2002. The ISO will launch a broad awareness campaign on new market opportunities targeted at potential load participants following Commission approval of the MD02 proposal.

The ISO also notes that a CPUC rulemaking recently has proposed reopening of the state Demand Bidding Program that allows loads to bid from $100 to $700 to be curtailed during periods of emergency. The program will be operated by the IOUs and will be triggered by ISO Alerts and Warnings as to pending shortages of operating reserves. The IOUs report that only 200 MW of load has subscribed to the program. There also has been recent dialogue to reinstate California's 20/20 program. Under this program, if load reduces consumption by 20 percent, it saves 20 percent on its bill and receives a rebate of 20 percent. The ISO also notes that the state's IOUs have reported enrollment under interruptible tariffs of slightly over 1000 MW, which is higher than participation during the summer of 2001 but lower than participation in other years. The ISO can curtail interruptible load during a Stage II emergency.

Finally, the ISO note that the California Consumer Power and Conservation Financing Authority (CCPCFA) intends to roll out a program for energy bidding by loads this summer. The program would be applicable to all loads aggregated by a single entity and bid into ISO markets. The ISO has met with representatives of the CCPCFA on several occasions to facilitate implementation of the program. If successful, the program could add significant demand participation to the ISO markets.

As the Commission is well aware, there are technical impracticalities involved in implementing demand responsiveness. June 19 Order at 62,555. For example, it would be desirable for the ISO to selectively curtail the load of an LSE when supply is short in real time, but, at present, the distribution utilities lack the technical capabilities to do so. The ISO is committed to establishing effective demand response and overcoming the existing technical barriers; but the Commission needs to realize that this is not a problem that can be resolved over night.

III.

CONCLUSION

Wherefore, for the foregoing reasons and the reasons set forth in its MD02 Filing, the ISO submits that the Commission should (1) extend the west-wide mitigation beyond September 30, 2002, (2) approve without modification the MD02 Phase I elements effective October 1, 2002 (with the locational market power tariff provisions to be effective July 1, 2002), (3) approve the MD02 Phases II and III elements on a conceptual basis, subject to the ISO filing revised Tariff sheets to reflect any revisions as a result of the stakeholder process proposed herein, and (4) reject intervenors' protests.

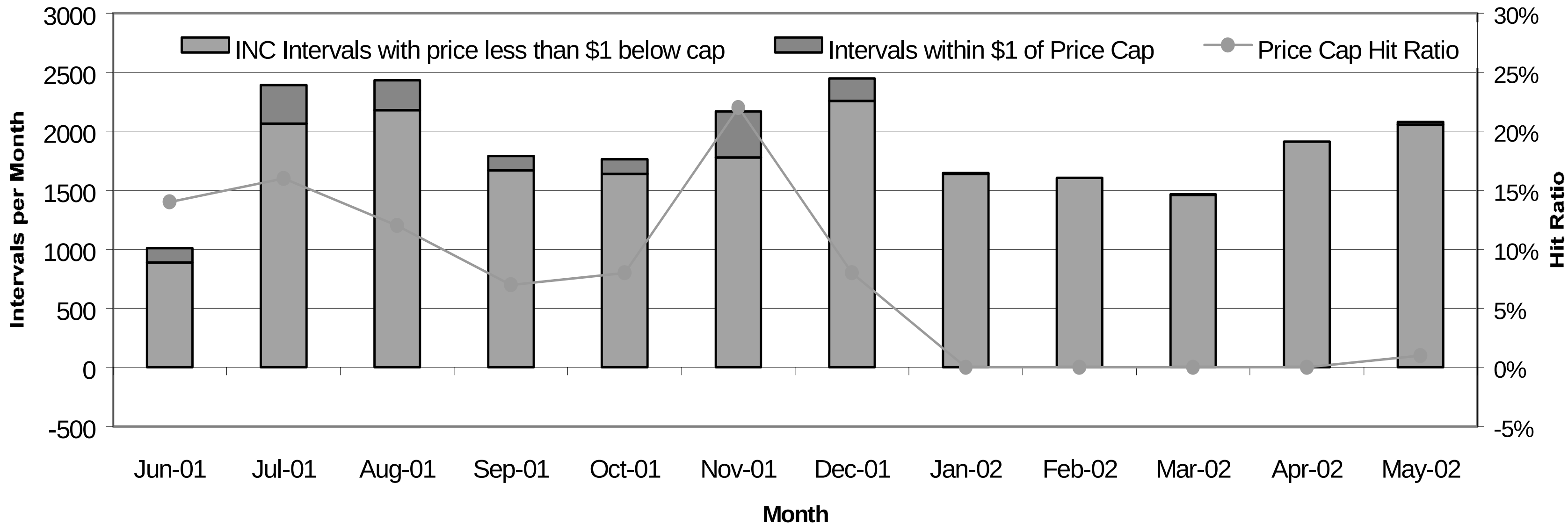
Respectfully submitted,

Charles F. Robinson
General Counsel
Anthony J. Ivancovich
Senior Regulatory Counsel
California Independent System
Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630

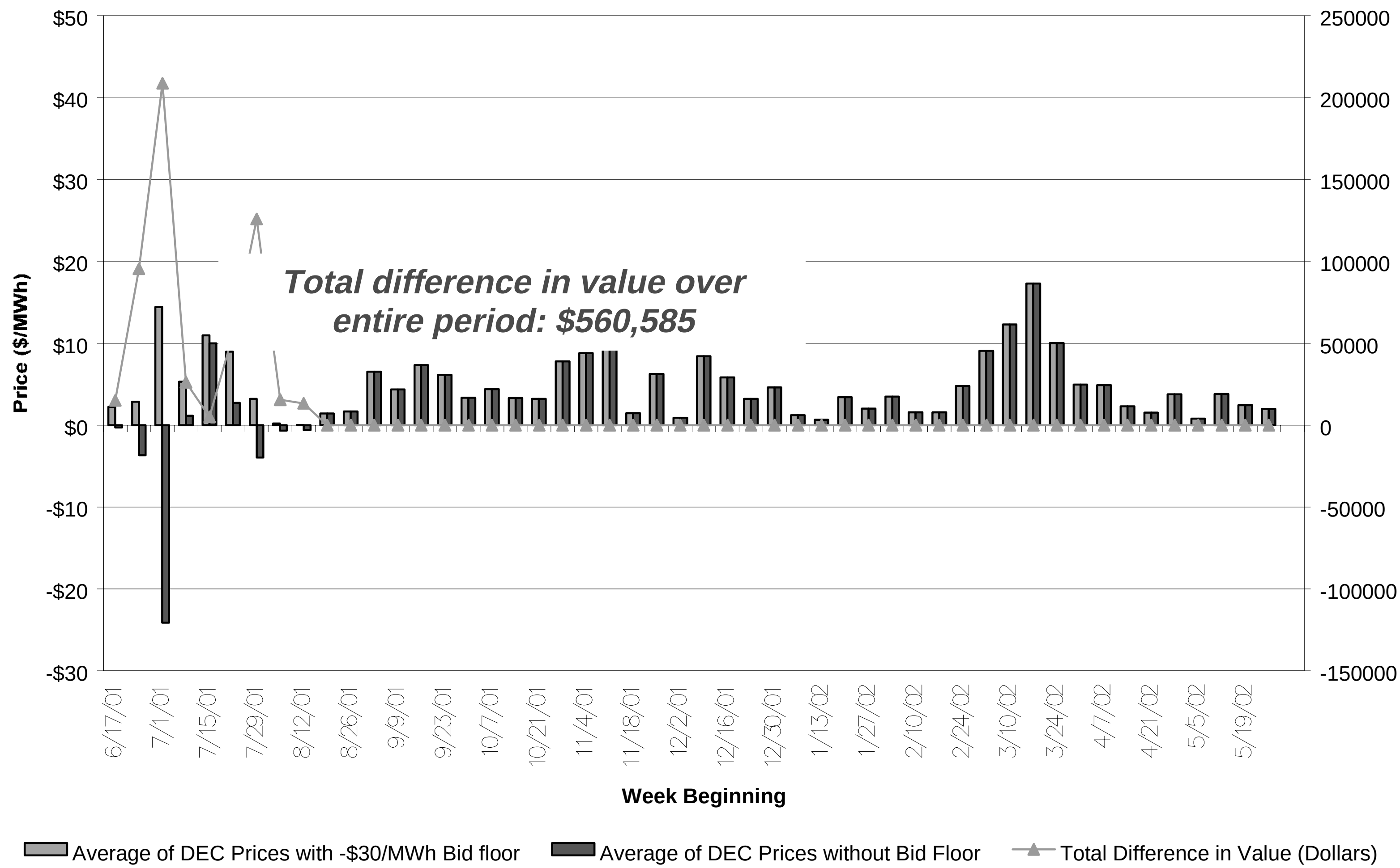
Filed: June 17, 2002

ATTACHMENT A

Price Cap Hits by Month



Weekly Average DEC Prices With and Without -$30/MWh Bid Floor June 20, 2001, through May 31, 2001



Methodology: Uses weekly average of ten-minute DEC prices weighted by ten-minute DEC volumes. Price with floor substitutes -$30/MWh for actual price whenever price is below -$30/MWh. Difference in Value is difference in weekly average price multiplied by total weekly volume.

ATTACHMENT B

CAISO Response to Protests Regarding the Proposed Competition Index

IEP Comments on Competition Index

IEP's sponsored Review of the California ISO's MD02 Proposal ("Review")[1] is critical of the ISO's proposed competition index. The Review states on page 43: "the broad concept of developing a benchmark against which one would assess the actual performance of the market, and proposing changes based on that comparison, is worth considering. Other market operators prepare regular assessments of their markets, using similar but not identical indicators. For example, PJM provides an estimate of the contribution to the fixed operating and capital costs of a peaking unit that would have been earned under perfect dispatch given the actual prices. This can be compared both historically and against the known fixed costs of these relatively simple units. The general trend is instructive, but the analysis is part of a larger evaluation and there is no automatic trigger for extensive mitigation efforts.

As the CAISO has recognized, the particular competition index it proposes is a new and untested mechanism. Nevertheless, the CAISO has proposed instituting wide-ranging market mitigation measures *automatically* whenever the competition index indicates that prices on an annual basis would exceed the CAISO's estimates of perfectly competitive prices by more than $5/MWh, which is a fairly tight tolerance. While the competition index may be a useful indicator of market competitiveness, to use it to institute wide-ranging mitigation measures automatically, without any assessment of whether the exercise of market power has actually given rise to the difference between actual prices and the benchmark, or whether there are problems in the calculation of the benchmark, would be premature, could be destabilizing and would raise the substantial possibility of reinstating the current west-wide mitigation procedures even when no market power has been exercised.

The circumstances that would cause the index to inappropriately trigger additional market power mitigation procedures include:

• Cost estimates may not be indexed to daily gas prices (especially important in the winter).
• Cost estimates may not include actual gas transportation costs to the burnertip.
• Cost estimates may not include actual emission allowance costs.
• Cost estimates may not reflect the increased likelihood of forced outages at some operating
levels.

The CAISO should consider calculating the competitiveness index using reference prices, which in most cases will be based on bids made by each generator that were accepted in the market in competitive conditions, instead of

[1] See IEP Protest, Review of CAISO MD02 Proposal, Cadwalader, Harvey, and Hogan, pp. 43-46.

administrative estimates of variable costs. Since the reference prices are determined during competitive conditions, there is no reason why they should not reflect the marginal cost of operating a generator. And using generators' bids would avoid the difficulty of estimate hard-to estimate costs such as the increased likelihood of outages at some operating levels."

ISO Response:

Most of the factors mentioned in the Review above have been carefully considered and already accounted for by the ISO in constructing the competitiveness index:

- Cost estimates use the daily gas prices in calculating 12-month index;
- Transportation costs are included since daily gas prices are priced at the burner tip;
- Emission costs do not enter the MCP and are treated as an uplift payment. This allows cost recovery without allowing it to unduly influence prices since the emissions markets tend to be illiquid and thinly traded;
- Cost of increased likelihood of forced outages will not occur if the unit is run within its designed capacity, which is what ISO assumes when estimating competitive cost;
- Professor Hogan's proposed alternative is likely to underestimate costs using reference prices. If uncompetitive prices are replaced with the competitive market reference prices, costs will be underestimated since the costs may have been lower under what were considered competitive conditions. The costs tend to be higher when there is higher demand in market and that is exactly when the market tends to be uncompetitive. Thus, using reference prices is a poor substitute to evaluating the costs under the real-time system conditions as is done in the competitive baseline calculations.

The Review goes on to state that “Additionally, even if the CAISO correctly estimates supplier marginal costs, its estimates of perfectly competitive prices will be calculated using a simplified model of supply and demand. Models abstract away from reality, but these abstractions may cause estimates of prices derived from models to be lower than prices that result in competitive markets under actual operating conditions. As a result, the CAISO’s estimates of perfectly competitive prices may be erroneous—which could cause the competition index to trigger extensive mitigation even in the absence of the exercise of market power. Although the detailed procedure that the CAISO’s model would use to estimate perfectly competitive prices has not been fully specified, experience reviewing prices calculated using optimizing models indicates that modeled prices may understate actual prices for the following reasons:

- Price calculations may not consider the impact of ramping limits or transmission constraints.
- Price calculations may ignore the impact of start-up or minimum generation costs, or other operating inflexibilities such as minimum run time and minimum down times.
- Price calculations may not consider environmental or other regulatory limits on production.
- Price calculations may not reflect the need for capacity to provide operating reserve or regulation.
- Price calculations may not consider temperature-related or tidal impacts on capacity.
- Price calculations often assume that next-day loads and outages were known with perfect certainty, so that the optimal combination of units has been committed to meet the next day’s load.
- Price calculations may assume that each generator is able to follow its dispatch signals perfectly.

A related, but separate issue pertains to the procedure the CAISO proposes to use to calculate prices if price-responsive load is on the margin. It proposes to set the benchmark price at “the marginal cost of the highest cost unit available to serve system load each hour,”95 but this is not the market-clearing price if price-responsive load is on the margin. In particular, this is not the market-clearing price when there are shortages, and the index should either be adjusted to account for the market-clearing price in these hours correctly, or to exclude these hours.”

ISO Response:

- Ramping limits apply mostly to real time imbalance energy service which is only a small part of the short term energy product. Furthermore, most real time service receive capacity payment as part of the reserve service payment. Transmission constraints will be considered in estimating competitive cost (to be phased in).

- Start-up cost or minimum load cost will be covered in RUC. Otherwise, if a unit starts on itself, it is most likely to be profitable in the ISO markets.

- Cost estimation will consider opportunity cost and operating reserve needs.

- Other impacts are too small to cause a material impact.

- Finally, and most importantly, the competitiveness index excludes hours of scarcity.

The Review also states "Finally, there are concerns regarding the procedure the ISO will use to calculate the actual costs that it will compare to its benchmark.

- The average price described in § 28.2.1.2 of the CAISO's proposed tariff appears to include DWR contract prices. Thus the index could be triggered if the contract price exceeds the benchmark price, even if market prices were consistent with or even below the index."

ISO Response:

The above is simply incorrect. Before the ISO's day-ahead energy market is implemented, the index would use CERS day-ahead purchase prices. CERS day-ahead purchase prices have proven to be very close to the Dow Jones published California regional hub prices. Therefore, the CERS purchase prices can be used as a good indicator of market conditions prior to the start of the formal day-ahead energy market.

The Review next states:

- "Net actual utility supply is deducted from the demand curve when calculating actual prices. But utility generators submit offer prices, and are dispatched according to their offer prices. And if these offer prices set prices, this means real-time prices could exceed the simulated prices for reasons that are unrelated to the exercise of market power by non-utility generators.

Given these concerns about the procedures the CAISO will use to compile its estimates of competitive prices, as well as the procedures it will use to calculate actual prices, it is possible that the competitive price level would exceed the benchmark prices by $5/MWh even if all non-utility generators were to bid in a competitive manner all of the time. The CAISO should refine the procedures it uses to calculate benchmark and actual prices along the lines suggested above."

ISO Response:

Here it is important to note that the ISO uses other indices to measure individual supplier's bid-cost markups. Therefore, if a utility generator is found to exercise market power, they will be reported to FERC and other regulatory agencies.

The Review also states "Additionally, the automatic consequences that would follow whenever actual prices exceed benchmark prices by more than $5/MWh should be removed, at least until the behavior of this prototype index is better understood. The CAISO could use the results of this index in its assessment of market behavior, and to support any filing it might make at FERC regarding changes to its market mitigation mechanisms, but it would need to compare the analysis of this index with the implications of other market indicators.

If the index were to trigger automatic regional mitigation, then both the threshold that would be used as the trigger and the consequences that would ensue should be reconsidered.

- The CAISO has not provided any justification for the selection of a $5/MWh threshold. The CAISO ought to provide such justification. The threshold that is used ought to reflect the likelihood of error in the CAISO's estimate of competitive prices, so to the extent that the CAISO cannot implement the proposed mechanism for modeling competitive prices, it should expand the threshold to reflect this likelihood of error.

- The CAISO also ought to consider more graduated modifications instead of reinstating full current west-wide mitigation. For example, the CAISO could request tightening of the AMP thresholds if the competitiveness index were to exceed a threshold level.

- The CAISO should also use this test to assess when it might be possible to relax mitigation—e.g., it could loosen the AMP thresholds if doing do is justified.

- Finally, the CAISO should modify its proposal so that whenever possible it will avoid mitigating those entities who have not exercised market power. Under the current proposal, the CAISO would subject all market participants to mitigation, even if only some market participants were deemed to have exercised market power. The CAISO claims that suppliers would be able to "self-regulate their own behavior in order to preclude intervention,"96 but suppliers can only regulate their own offer prices, not the offer prices of other suppliers (unless suppliers explicitly coordinate their offer prices, an approach which the CAISO likely does not mean to endorse). Moreover, focusing intervention on those who have exercised market power is a more effective disincentive to such behavior."

ISO Response: Justification of the $5/MWh threshold:

First, the competitiveness index was designed to provide sufficient revenues to cover all variable costs and a contribution to annual fixed costs. In addition, revenues from ancillary service payments, payments under long term contracts and annual capacity contract payments should be considered in determining whether costs of new plants additions will be fully covered.

Below are three separate justifications for the $5/MWh threshold:

1. The threshold is the result of a conservative calculation. Consider the following example using the 90th percentile heat rate of 12,000BTU/kWh and $3.00/MMBTU gas cost. This translates to an average cost of $36+$6 = $42/MWh. Therefore, the $5/MWh threshold represents a 12% adder which is in the range of 10-15% mark-up above competitive costs previously considered adequate in FERC rulings.

2. Historical experience also shows that the threshold is appropriate. For instance, the May 2002 ISO monthly market analysis report compares the average price to the competitive benchmark price. The comparison shows that the California market exceeded $5/MWh threshold mark-up from November 2000 through June 2001. However, during the first 2 years if CAISO operation, the average cost was $30.5/MWh and adder was only $2.5/MWh. During this period the market was competitive and proved to provide sufficient incentives for new investment. This can be seen by the number of applications for new power plants filed with the CEC as shown in the following table.

Capacity of CA Energy Commission Certification Permits, Filed in 1998 and 1999

Year AFC Filed	Capacity Planned	Capacity Withdrawn	Net Capacity Planned
1998	2803	0	2803
1999	4940	0	4940

Source: California Energy Commission website, Thermal Power Plant Projects
Before the California Energy Commission 1976-2002. Last updated February 22, 2002.
http://www.energy.ca.gov/sitingcases/projects_since_1976.html

3. The $5/MWh is also justified when looking at other ISO markets. In a May 2002 analysis conducted by Bushnell and Saravia[2], the authors report a mean cost of $40.17/MWh with an average mark-up of $2.88/MWh over the period of May 1999 through September 2001.

Finally, it is important to note that the triggered mitigation is only temporary measure (i.e., 6 months or until FERC orders alternative mitigation). After the temporary period, if the market is still uncompetitive, a more selective mitigation on those who actively exercised market power can be implemented or their market based rate authority can be revoked. It is important to emphasize that the triggered mitigation is a temporary measure to stop the impact of excessive market power, it is not intended to be permanent mitigation for normal market operation. It is more important for the temporary mitigation it to be simple and quickly implemented rather than comprehensive and perfect. The long-term goal is to set the correct market structure and relieve as much mitigation as possible.

[2] "An Empirical Assessment of the Competitiveness of the New England Electricity Market," James Bushnell and Celeste Saravia, May 2002.

SMUD Comments on the Competitiveness Index

SMUD proposes an alternative index to the ISO's proposed 12-month competitive index and mitigation. Specifically, SMUD proposesto:

- Use daily gas prices at selected CA trading points;
- Use a fixed spark spread of 15 (equivalent to assuming the system marginal generation heat rate is 15,000BTU/kWh);
- Use the above heat rate and daily gas price to calculate a threshold for a rolling 365 day period and the actual market price is not expected to exceed it.

ISO Response:

Although SMUDs proposal is attractive in that it provides simplicity and transparency, it is inaccurate and would allow too much margin when gas prices are high. First, SMUD's proposal would be inaccurate since it does not consider such things as supply and demand conditions and opportunity costs. Second, it allows too much margin at high gas prices. For instance, assuming the actual marginal heat rate average of 12,000BTU/kWh, the allowable margin above the cost would be SMUD's proposed 15,000BTU/kWh heat rate minus the actual12,000BTU/kWh heat rate, or 3,000 BTU/kWh. Since this allowable margin above cost is determined by 3*Gas Price, it changes dramatically with gas prices. For example, if the gas price is $3.00 (likely long run cost), the margin would be $9.00/MWh. Moreover, if the gas price were higher at say $6, then the margin would be $18/kWh. Since the margin is designed to be a return to fixed cost or investment, the inflated margin with higher gas price is not justified, since higher gas price only increase variable costs not fixed costs.

SMUD also suggested using a factor of 50 times the gas price as the daily DCBC.

This would enable suppliers to exercise significant market power. For example, assume that the gas price increased by $5, and further assume the marginal heat rate is at 15,000 BTU/kWh. The actual cost increase is only $75/MWh. However, SMUD's proposed formula would allow the cap to increase by $5x50 = $250/MWh. So the increased cap not only allows for more actual cost recovery, it would also allow for the exercise of significant market power.

Reliant Comments on the Competitiveness Index

Reliant argues that the Competition Index should consider costs and prices throughout the entire WSCC market.

However, without a west-wide market monitoring unit, it is difficult to calculate an accurate competition index for the entire west. Calculating the index for California is the right first step with the eventual goal to extend the calculation to the entire WSCC market. FERC's June 19th order for west-wide mitigation used exactly this type of approach where the California marginal system cost is used as the benchmark to set the bid cap for the entire WSCC region.

In the mean time, it is generally agreed upon that California has the highest cost of power generation due to higher fixed costs and higher fuel and emission costs. In practical terms, the chances are very high that a California unit would be on the margin except for some local reliability areas in the Northwest or Southwest. Localized market conditions would not set the price for the market in general.

Reliant also argues that the $5/MWh threshold does not account for normal market price fluctuations.

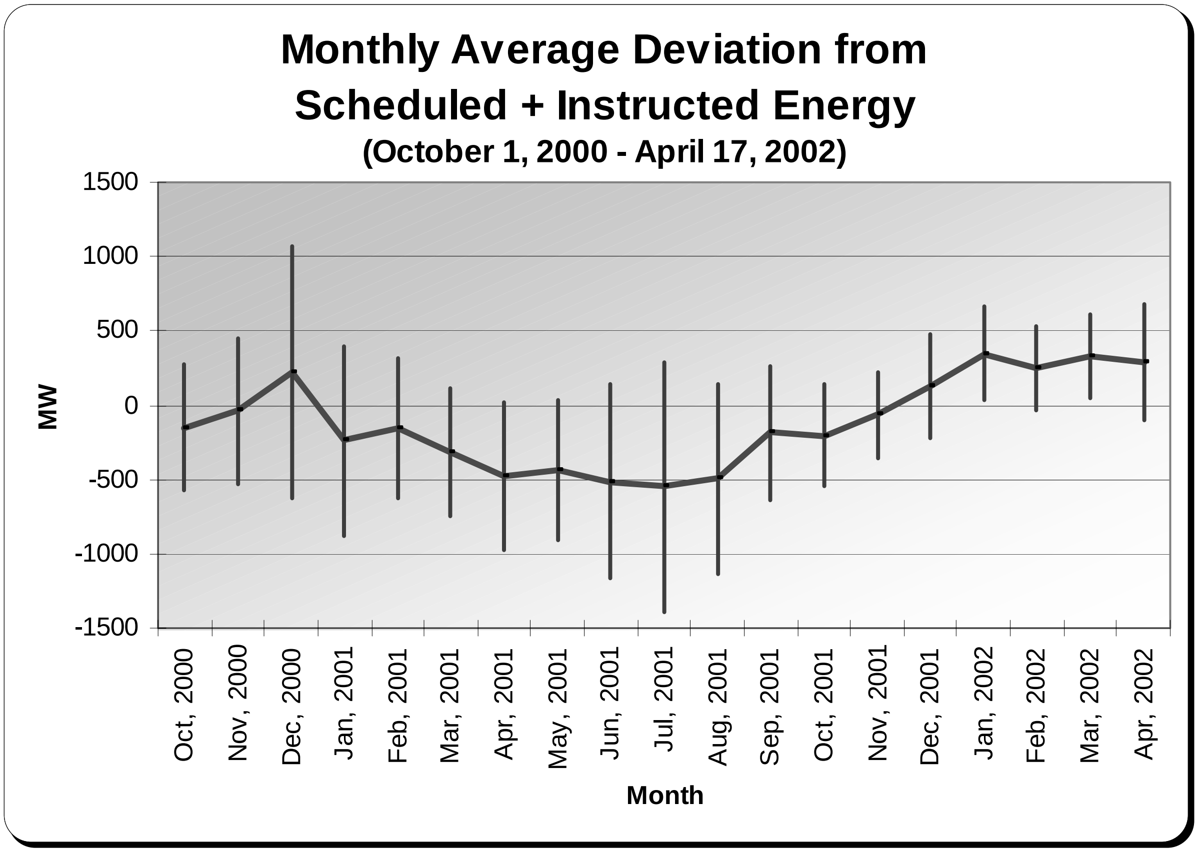
[See response to IEP above]

Finally, Reliant argues that the mitigation measures should end upon some well-defined return to pre-mitigation price conditions. If extended beyond some set time, the Commission should have the authority to step in and review the application of the measures.

The ISO notes that its MD02 proposal provides that the mitigation will end in the event that the market is restored to competitive conditions. Furthermore, the ISO proposal includes a 6 month limit or until FERC review and order alternative mitigation for the temporary mitigation measures to be in place.

ATTACHMENT C

Monthly Average Deviation from Scheduled + Instructed Energy

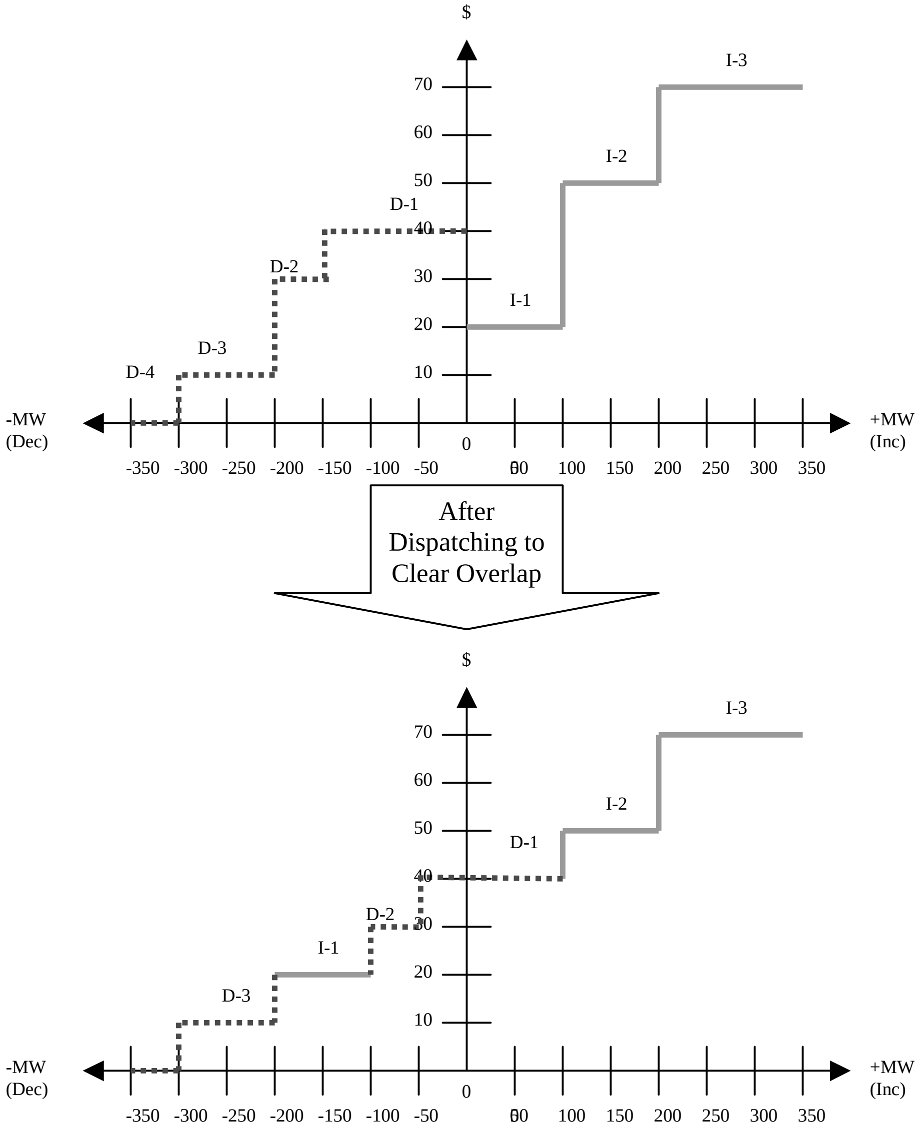


In any given settlement interval, some generators may be producing more energy than is expected and others may be producing less energy than is expected. The net effect of combining the over- and under-generation is the net deviation from scheduled + instructed Energy. The above chart shows the monthly average deviation from schedule + instructed energy (in red). The chart indicates that throughout 2001, generators tended to under-deliver on their obligations (as defined by their Energy schedules and ISO Dispatch instructions). In 2002, we have observed a tendency to over-deliver (which is especially troubling when the dispatchers are actively battling over-generation - generation exceeding load plus interchange - conditions). Our objective is to see the monthly average deviation from scheduled + instructed Energy trend towards zero.

Of equal or greater concern is the variability of response that we observe. This is indicated on the chart by the vertical bars representing one standard deviation around the average. Since the band defined by one standard deviation from the average represents only 65% of the occurrences, there are a 35% of the settlement intervals in which the actual net generation lies outside of the band defined by the vertical bars. Our objective is to see this band narrow so that there is very little variation from the average.

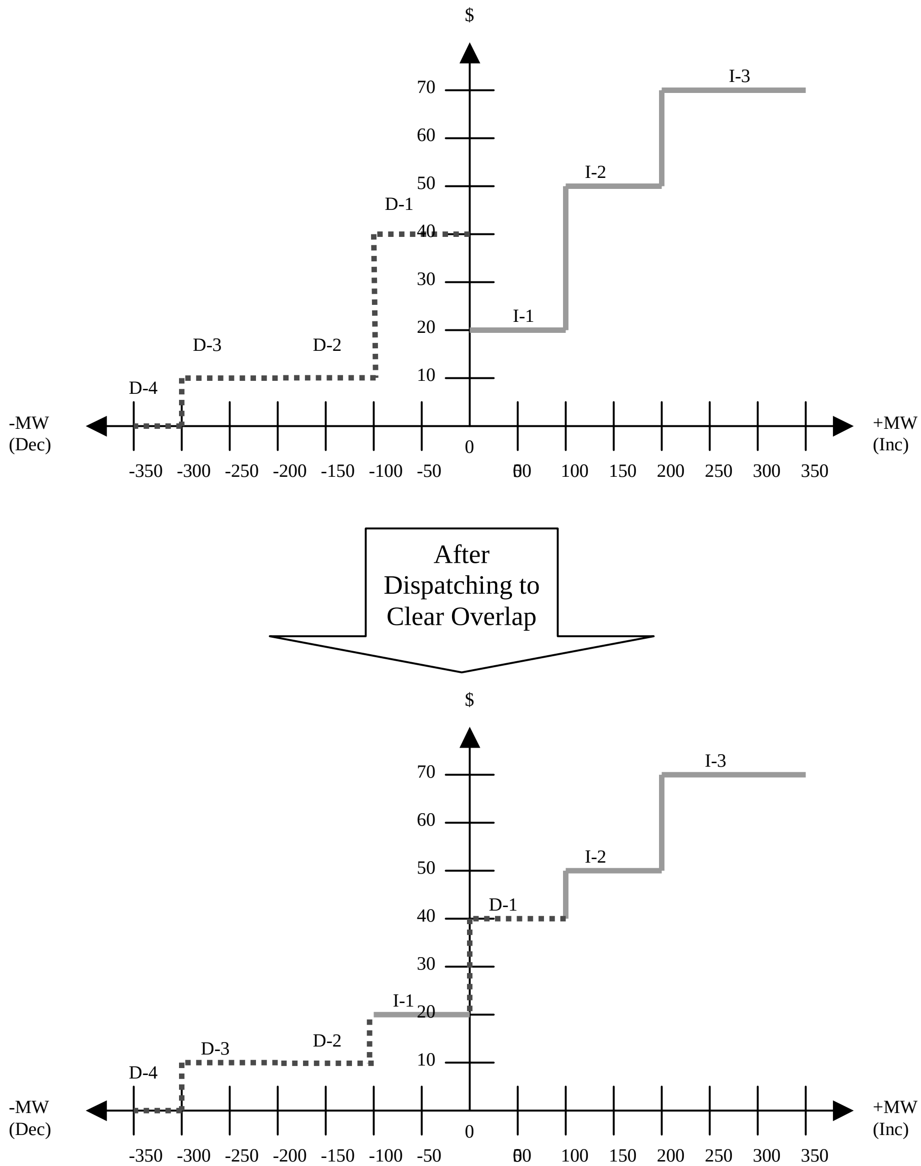
ATTACHMENT D

Example 1



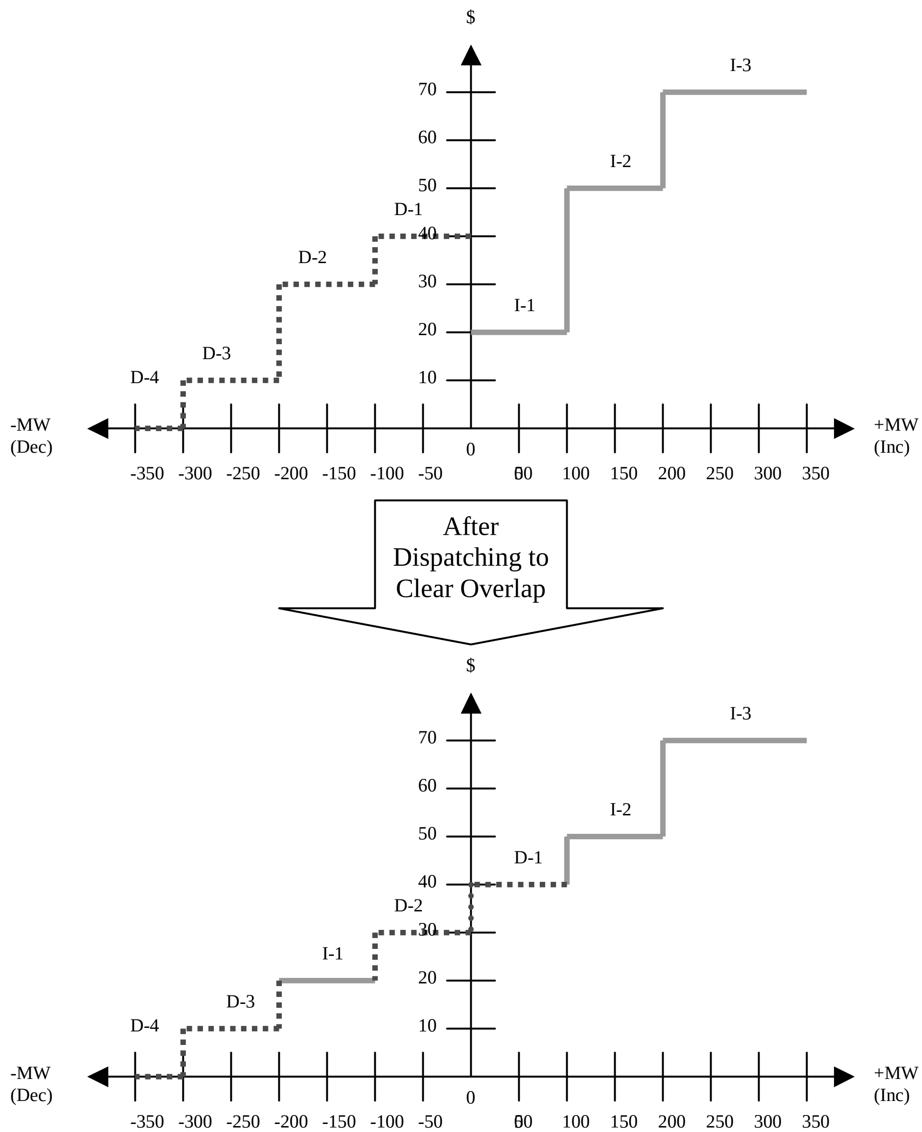
Imbalance Energy Requirement (MW)	MCP ($/Mwh)
-150	$20
-100	$30
-50	$40
0	$40
50	$40
100	$40
150	$50

Example 2



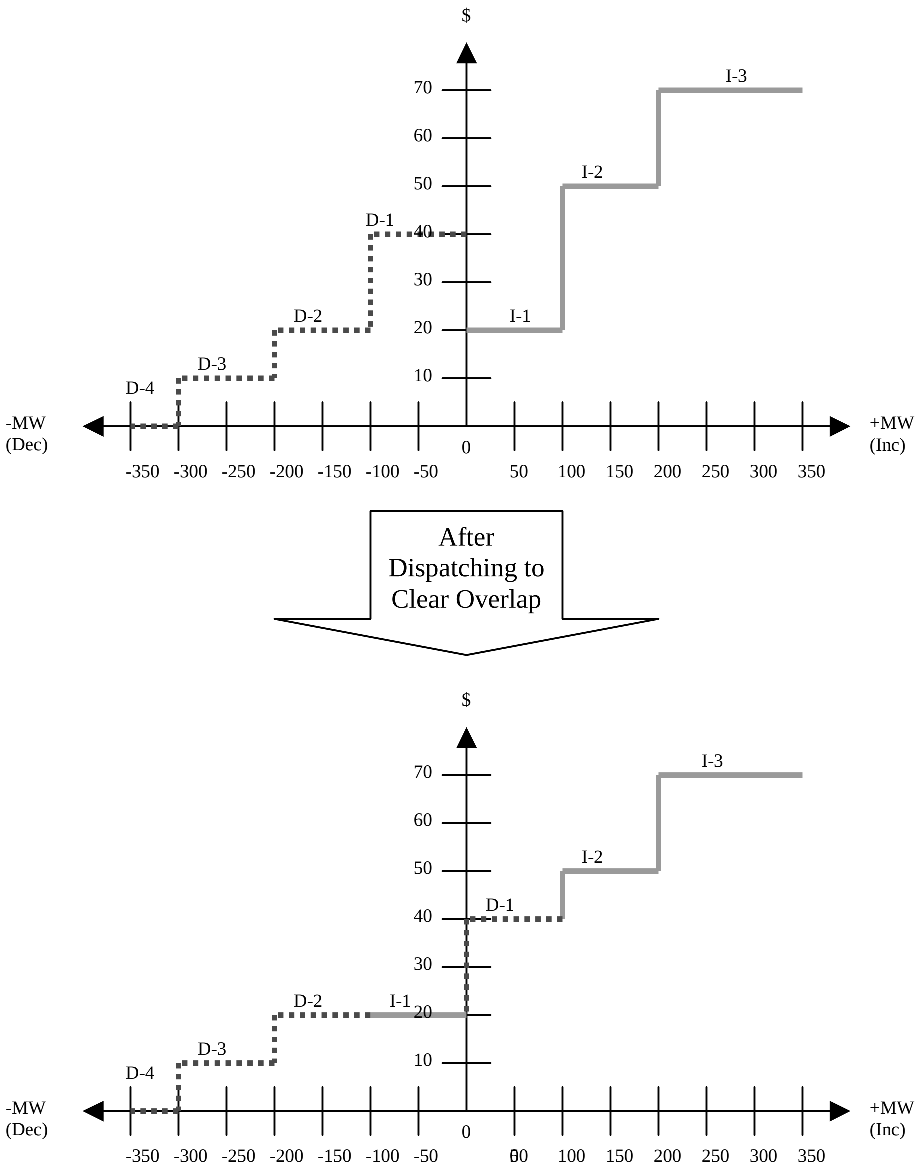
Imbalance Energy Requirement (MW)	MCP ($/Mwh)
-150	$10
-100	$20
-50	$20
0	$20
50	$40
100	$40
150	$50

Example 3



Imbalance Energy Requirement (MW)	MCP ($/Mwh)
-150	$20
-100	$30
-50	$30
0	$30
50	$40
100	$40
150	$50

Example 4



Imbalance Energy Requirement (MW)	MCP ($/Mwh)
-150	$20
-100	$20
-50	$20
0	$20
50	$40
100	$40
150	$50

CALIFORNIA ISO

California Independent
System Operator

June 17, 2002

The Honorable Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange
Docket No. EL00-95-001

California Independent System Operator Corporation
Docket No. ER02-1656-000

Dear Secretary Salas:

Enclosed for electronic filing please find the Motion for Leave to File Answer and Answer of the California Independent System Operator Corporation to Protests.

Thank you for your assistance in this matter.

Respectfully submitted,

Anthony J. Ivancovich
Counsel for The California Independent
System Operator Corporation

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the Motion for Leave to File Answer and Answer of the California Independent System Operator Corporation to Protests on each person designated on the official service list compiled by the Secretary in the above-captioned dockets.

Dated at Folsom, California, on this 17th day of June, 2002.

____

Anthony J. Ivancovich