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July 22, 2003

Hon. Magalie Roman Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

**Re: *California Independent System Operator Corporation***
**Docket Nos. ER02-1656-___ and EL01-68-___**

Dear Secretary Salas:

Enclosed for filing are one original and six copies of the California Independent System Operator Corporation's Amendment to the Comprehensive Market Design Proposal, submitted in the above-captioned proceedings. An electronic copy of the Notice of Filing, for publication in the Federal Register, is contained on the 3.5 inch floppy diskette included with this filing.

Also enclosed are two extra copies to be time/date stamped and returned to us by the messenger. Thank you for your assistance. Please contact the undersigned if you have any questions regarding this filing.

Respectfully submitted,

David B. Rubin

Counsel for the California Independent System Operator Corporation

Enclosures

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

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| California Independent System Operator Corporation | ) ) | Docket No. ER02-1656-___ and EL01-68- ___ |

**AMENDMENT TO**
**COMPREHENSIVE MARKET DESIGN PROPOSAL**

Filed: July 22, 2003

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July 22, 2003

The Honorable Magalie R. Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

**Re:** ***California Independent System Operator Corporation***

**Docket Nos. ER02-1656-000 and EL01-68-000**
**Amendment To Comprehensive Market Design Proposal**
**And Request For Expedited Consideration**

Dear Secretary Salas:

Pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, Section 35.13 of the Commission's regulations, 18 C.F.R. § 35.13, and Rules 212, 216 and 2008(a) of the Commission's Rules of Practice and Procedure, 18 C.F.R. §§ 385.212, 385.216, and 385.2008(a) (2002), the California Independent System Operator Corporation ("CAISO")[1] hereby submits for filing an original and six copies of its Amendment to the Comprehensive Market Design 2002 ("MD02") proposal contained in Amendment No. 44 to the ISO Tariff.[2]

By this filing, the CAISO requests that the Commission approve in its entirety the amended Comprehensive Market Design Proposal ("Proposal") provided as Attachment A hereto.[3] To facilitate the Commission's evaluation of

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[1] Capitalized terms not otherwise defined herein are defined in the Master Definitions Supplement, Appendix A to the ISO Tariff, as filed August 15, 1997, and subsequently revised.

[2] The CAISO filed Amendment No. 44 on May 1, 2002 ("May 1 Filing"). The CAISO filed Tariff language for the MD02 long-term market design elements on June 17 and 28, 2002.

[3] In its January 10, 2003 Status Report of the California Independent System Operator Corporation ("January 10 Status Report"), the CAISO indicated that, consistent with the

the Proposal, the CAISO's filing is comprised of two primary components – the Proposal itself, provided as Attachment A, and the instant Transmittal Letter. The Proposal describes in detail the specific market design elements for which the CAISO seeks Commission approval, and is structured to be a comprehensive, self-contained statement of the CAISO's proposed market redesign. Commission approval of the Proposal without significant modification will permit the CAISO to proceed expeditiously to contract with a vendor to develop the software and systems required to implement the centerpiece of the proposal, namely, an Integrated Forward Market ("IFM") based on Locational Marginal Pricing ("LMP").

The Transmittal Letter provides additional explanation of and arguments in support of the Proposal. In particular, the Transmittal Letter attempts to identify and discuss the following: (1) details of the major design elements of the Proposal and the CAISO's rationale in proposing these elements; (2) the significant issues raised by stakeholders regarding the Proposal and the CAISO's views on those issues,[4] and (3) the relationship between the proposed design elements and specific issues raised in the Commission's Standard Market Design Notice of Proposed Rulemaking[5] and April 28, 2003 White Paper on Wholesale Power Market Platform ("White Paper"). The Transmittal Letter also identifies certain elements of MD02 where the CAISO is committed to working with stakeholders to finalize specific design details that do not need to be resolved prior to executing a contract for software and systems development. The fact that some details of the design have not yet been finalized does not detract from the internal consistency of the comprehensive MD02 design or the CAISO's ability to proceed with software and systems development to implement MD02 and, therefore, should not deter the Commission from approving the Proposal in its entirety.

For the reasons described below, the CAISO respectfully requests that the Commission, in conjunction with its approval of the Proposal, also (1) permit the CAISO to withdraw the Tariff filings concerning the MD02 long-term design

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Commission-approved approach already taken by other entities (*e.g.*, Midwest ISO, RTO West, Grid South, and SeTrans RTO), the CAISO would seek Commission approval of market redesign elements before submitting detailed Tariff language. The CAISO proposed that approach for several reasons. First, a process that required the CAISO to develop Tariff language and then wait for Commission approval before proceeding with vendor selection and software development would delay the redesign process significantly. Second, the CAISO's proposed approach would provide the CAISO with adequate time to develop a new, more simplified and effective Tariff consistent with the tariffs of other independent system operators.

4 By identifying potential issues raised by the Proposal and setting forth the CAISO's position on such issues, the CAISO hopes to facilitate the Commission's review of and prompt action on the Proposal.

5 *Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design,* Notice of Proposed Rulemaking, FERC Stats. & Regs, ¶ 32,563 ("SMD NOPR").

elements that the CAISO submitted on June 17 and June 28, 2002, and (2) endorse the CAISO's proposed process for finalizing the detailed tariff language implementing the Proposal.

To the extent necessary, the CAISO requests waiver of any applicable Commission filing requirements. Because the CAISO requires Commission approval prior to contracting for development of the software and systems needed to implement the Proposal, the CAISO cannot propose a specific effective date at this time. Nevertheless, the CAISO requests that the Commission approve the Proposal within the standard 60-day consideration period for filings under Section 205 of the Federal Power Act. Once the Commission approves the Proposal, and provided there are no significant changes, the CAISO will immediately proceed to the final stage of contract negotiations with the primary vendor. The CAISO and the vendor will then develop a feasible implementation schedule that allows adequate time for testing. In that regard, the ultimate implementation schedule will depend on the development of other systems besides the primary IFM/LMP system, including the Settlement system and the Congestion Revenue Rights ("CRR") allocation and auction software. The CAISO will inform the Commission of the implementation schedule in its monthly MD02 status report subsequent to the development of a firm schedule.[6]

## I. BACKGROUND

### A. Introduction

In the spring of 2000, in compliance with Commission orders, the CAISO initiated a project to redesign its congestion management system to eliminate the identified flaws in the original zonal approach. With the onset of California's electricity crisis in the summer of 2000, the CAISO recognized that redesign of its congestion management system necessarily had to be undertaken in the larger context of a thorough diagnosis of California's restructured electric industry and a comprehensive assessment of the CAISO's appropriate role in improving a dysfunctional market. Accordingly, in December of 2001, the CAISO initiated the Market Design 2002 (*i.e.,* MD02) project, to redesign the CAISO's markets in a manner that would make them function more effectively and efficiently, thereby addressing certain underlying causes of the electricity crisis. The MD02 project was given further direction by the Commission's December 2001 Order which required the CAISO to file, by May 1, 2002, a plan for redesigning its congestion management system and implementing a Day-Ahead energy market. The

[6] As the Commission is well aware, the CAISO has made considerable progress to date by putting itself in a position to finalize terms and execute contracts with vendors upon Commission approval of this Proposal. To be specific, the CAISO has issued requests for proposals ("RFPs") for the IFM/LMP, CRR and Settlement systems, received vendor bids and completed bid evaluations for two of the three systems. Further, the CAISO is in the final stage of bid evaluation for the third system. Additional details on these activities have been provided to the Commission in the CAISO's monthly MD02 status reports.

CAISO's May 1 Filing of the MD02 Comprehensive Market Design Proposal (Amendment No. 44 to the CAISO Tariff) discusses these matters in substantial detail.

Since the beginning of the MD02 project, the CAISO has conducted numerous stakeholder activities to educate market participants about the LMP system that has proven successful in the markets operated by the eastern independent system operators, to understand stakeholders' needs and concerns, to make appropriate improvements to the design, and to attempt to develop broad support for the Proposal. The CAISO recognizes that it is probably impossible to garner universal support for a particular market design. Moreover, with the California crisis out of the headlines, there are parties who might argue that the CAISO should not undertake a substantial market redesign at this time. The reality, however, is that the current wholesale spot market and congestion management system are structurally flawed. While the crisis that created havoc during 2000 and 2001 and produced unjust and unreasonable prices has abated, many of the underlying structural causes of that crisis remain unresolved. The State of California has been taking measures to address issues within its purview, most notably ensuring the adequacy of supply. In that regard, the California Public Utilities Commission ("CPUC") has an ongoing procurement proceeding in which it is addressing resource adequacy matters by developing new procurement rules for the investor-owned utilities ("IOUs") it regulates. The CAISO is participating in that proceeding and has been working with the State in various proceedings trying to identify needed transmission system improvements.

None of these activities reduce the need for a comprehensive redesign of the CAISO's congestion management system and CAISO-operated spot markets. The CAISO market redesign in and of itself is not sufficient to remedy the underlying causes of the California crisis. In conjunction with the State's resource adequacy programs and other activities designed to improve the State's electricity infrastructure, however, the new market design will form a necessary foundation for the development of an adequate electricity infrastructure and a reliable supply of electricity at reasonable prices for California consumers. In particular, the Proposal will improve the climate for investment in California by eliminating uncertainty about the future market rules and establishing a transparent, proven system for allocating access to the grid and pricing spot market energy and provide several crucial features for a well-functioning electric industry, including a forward spot energy market to facilitate short-term balancing of supply and demand, transparent forward spot market prices that reflect transmission constraints, rules for forward allocation and pricing of transmission that are consistent with Real-Time operation, and effective protection for consumers against the exercise of market power. Moreover, the CAISO has taken great care to ensure that the Proposal constitutes a coherent, internally-consistent and comprehensive design that incorporates, to the extent feasible, design features that meet the needs of market participants, address the concerns of stakeholders, and will facilitate the prompt return to health of California's electricity sector.

### B. Procedural History

On May 1, 2002, the CAISO filed its Comprehensive Market Design Proposal. At that time the CAISO proposed to implement MD02 design in three phases:

- Phase I included, *inter alia*, market power mitigation measures designed to prevent physical and economic withholding, Real-Time economic dispatch and use of a single Energy bid curve;

- Phase II had as its centerpiece an IFM and included, *inter alia*, elimination of the market separation rule and balanced schedule requirement and implementation of simultaneous Congestion Management, an Energy market, and Ancillary Services ("A/S") procurement utilizing a security constrained unit commitment process on a zonal basis; and

- Phase III provided for implementation of the full network model, redesigned Firm Transmission Rights ("FTRs"), a resource adequacy requirement for Load Serving Entities ("LSEs") and an integrated Congestion Management, Energy and A/S market based on LMP.

On June 17, 2002, as supplemented on June 28, 2002, the CAISO submitted Tariff provisions for the Phases II and III market design elements.

On July 17, 2002, the Commission issued an order in which it accepted, rejected and modified, in part, the CAISO's May 1 Filing.[7] The Commission ruled on the merits of the Phase I elements of the Comprehensive Market Redesign Proposal. While the Commission did not rule on the merits of the Phase II and Phase III elements, the Commission directed the CAISO to expedite implementation of the Phase II reforms. Further, the Commission authorized the CAISO to expend funds for the development of LMP and the full network model, but determined that the specifics of implementation of those elements should be addressed in technical conferences established by the July 17 Order.[8]

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[7] *California Independent System Operator Corporation,* 100 FERC ¶ 61,060 (2002) ("July 17 Order").

[8] On August 16, 2002 and August 21, 2002 the CAISO filed Tariff language in compliance with the July 17 Order. On September 20, 2002, the CAISO also filed an update to Amendment No. 44 proposing the following modifications to the Phase 1 elements set to take effect on October 1, 2002.

From August 13 through August 15, 2002, Commission staff, market participants and CAISO staff held a technical conference in San Francisco to discuss the MD02 long-term market design proposal. Following the technical conference, four working groups were established to discuss and attempt to resolve outstanding issues regarding the proposed MD02 long-term market design. These working groups were as follows: the Transitional Issues Working Group; the Integrated Forward Markets Working Group; the Resource Adequacy Working Group; and the LMP/Congestion Revenue Rights[9] Working Group.

On October 11, 2002, the Commission issued an order on rehearing of the July 17 Order and on the August 16 and 21, 2002 compliance filings[10] which: (1) reversed the Commission's prior directive that imports are subject to Automatic Mitigation Procedures ("AMP") and directed that they remain price-takers and bid $0/MWh into the CAISO markets; (2) eliminated the application of a $91.87/MWh price screen to bids taken out of merit order to address intra-zonal congestion in AMP; (3) clarified that a supplier may increase or decrease a real-time bid for capacity not already accepted through the Hour-Ahead market, but may only decrease a real-time bid for capacity already accepted through the Hour-Ahead market; (4) accepted the CAISO's proposal to delay implementation of software to clear the Price Overlap until the CAISO implements uninstructed deviation penalties; (5) encouraged the CAISO to work with stakeholders to develop a long-term residual unit commitment ("RUC") proposal; and (6) directed the CAISO to implement by January 31, 2003 the so-called "Phase II Lite", a non-optimized forward energy-only market, by eliminating the balanced schedule requirement and the market separation rule.

On October 25, 2002, the Commission issued an order[11] approving the CAISO's proposed modifications to the Phase I elements and directing the CAISO to move the deadline for submitting Hour-Ahead schedules from 120 minutes before the operating hour to 135 minutes before the operating hour.[12]

On November 11, 2002, the CAISO filed a request for rehearing of the Commission's directive to implement the Phase II Lite market by January 31, 2003. The CAISO indicated that, upon further examination, it could not

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9 The CAISO adopted the term CRRs to designate the congestion hedging instrument to be implemented in conjunction with LMP and to clearly distinguish this new instrument from the CAISO's existing FTRs which are based on the zonal congestion management approach.

10 *California Independent System Operator Corporation*, 101 FERC ¶ 61,061 (2002) ("October 11 Order").

11 *California Independent System Operator Corporation*, 101 FERC ¶ 61,084 (2002) ("October 25 Order").

12 On November 25, 2002, the CAISO made a filing in compliance with the October 25 Order.

implement the Phase II Lite market by January 31, 2003. On November 27, 2002, the Commission issued an order: (1) rescinding its previous directive that the CAISO implement the Phase II Lite Day-Ahead market by January 31, 2003, and (2) directing the CAISO to submit monthly reports on MD02 implementation beginning in January 2003.

On November 25, 2002, each of the four Working Groups filed a statement setting forth the issues raised in each Working Group and whether such issues had been resolved or were still outstanding. On December 2, 2002, the CAISO filed a lengthy Statement of Position on the outstanding market design issues identified by the four Working Groups. Also on December 2, 2002, the CAISO submitted its presentation for a December 9 technical conference. The presentation, *inter alia,* showed the CAISO's MD02 implementation plan and efforts. On December 9, 2002, Commission staff held a technical conference on MD02 in Washington, DC. At the technical conference, the CAISO presented a schedule for implementing MD02. Representatives from the Working Groups also reported on the progress of their groups' efforts.

On January 10, 2003, the CAISO filed its first monthly MD02 status report and has continued to file status reports on a monthly basis ever since.

### C. Stakeholder Process

It is important for the Commission and stakeholders to keep in mind that the CAISO's MD02 effort essentially began well before the electricity crisis of 2000-2001. In the Spring of 2000, the CAISO commenced its "Congestion Management Reform" ("CMR") project, an effort that involved extensive stakeholder discussions and outreach. While that effort was ultimately derailed by the energy crisis, the work completed in connection with that project formed the foundation of the MD02 market redesign. The MD02 stakeholder process began in earnest in January 2002 with a four-day market design forum hosted by the CAISO. From January through April 2002, the CAISO conducted an extensive stakeholder process to guide the development of the MD02 proposal ultimately filed at the Commission on May 1, 2002 (*see* summary of stakeholder activities on page 11 of Attachment A to the May 1 Filing).

As noted above, subsequent to the May 1 Filing and the July 17 Order, the CAISO has met with stakeholders in Commission-sponsored technical conferences and via the Working Group process established under the Commission's direction. The CAISO also worked with stakeholders via the Joint Application Design ("JAD") process to resolve technical issues associated with the market redesign. Finally, the CAISO has had numerous meetings with individual stakeholder groups, including the IOUs, the CPUC, suppliers, and municipal utilities to identify issues of concern, understand stakeholders' views on such issues and attempt to work toward their resolution. The remainder of this section provides a review of these activities.

### 1. The Working Groups

The four Working Groups established subsequent to the August 13-15 technical conference met regularly through the Fall of 2002. Generally, two Working Groups would meet on back-to-back days and on alternating weeks. The purpose of the Working Groups was to evaluate and refine the long-term market design elements, identify issues raised by the CAISO's Comprehensive Market Design Proposal, explore alternative solutions to those proposed by the CAISO, and seek stakeholder consensus where possible. Meetings were open to all who wished to attend, and representation included a wide range of stakeholders. The Working Groups resolved many issues that are reflected in the Proposal.[13] The Working Groups also identified a number of issues for which there was no consensus resolution. This Transmittal Letter discusses the CAISO's proposed resolution of many of the unresolved Working Group issues.

### 2. Joint Application Design Sessions

The CAISO also convened several JAD sessions with stakeholders to resolve details of the implementation of numerous market design elements. The JAD sessions, which are primarily intended to resolve technical implementation issues, typically consisted of no more than a dozen Market Participants (representing a cross section of market interests) plus CAISO staff. These sessions focused on implementation and software development issues – the "how" as opposed to the "what" – and generally included technical representatives who understood the intricacies of design elements and software.

The CAISO held three two-day Phase II and Phase III JAD sessions between December 5 and December 18, 2002. There were two follow-up conference calls on January 6 and 8, 2003 to discuss and reach consensus on remaining JAD issues. The issues raised throughout the JAD sessions were documented and posted on the CAISO website, and updated as progress was made in addressing each issue. The purpose of these JAD sessions was to present and resolve technical implementation issues associated with certain Phase II and Phase III market design elements prior to the release of the "Integrated Forward Market and Locational Marginal Pricing Using the Full Network Model Request for Proposals" ("IFM/LMP RFP"). The final Phase II and Phase III JAD Issues Matrix was filed with the Commission as Attachment F to the CAISO's January MD02 Status Report.[14]

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[13] *See* Integrated Forward Markets Working Group Comments and Statement of Issues: List of Issues for December 9, 2002 FERC Technical Conference.

[14] The first monthly status report to the Commission was filed on January 10, 2003, which included Attachment F - MD02 Topics Discussed in Working Group and JAD Sessions.

### 3. Market Issues Forum Meetings and Stakeholder Online Forum

Since its inception, the CAISO has held monthly Market Issues Forum ("MIF") meetings to discuss with stakeholders pertinent market-related issues at the CAISO, including MD02 issues. Since spring of 2002, the CAISO has provided regular MD02 updates at these MIF meetings and received stakeholder input. At the January 15, 2003 MIF meeting, stakeholders expressed concern that a number of the JAD issues were not strictly technical implementation matters, but in fact were policy issues that needed to be vetted with a broader group of stakeholders. To accommodate stakeholder dialogue in an efficient manner as policy issues continued to emerge, the CAISO established a Stakeholder Online Forum with the communications firm that was used for the 2001 CMR process. The CAISO utilized the Stakeholder Online Forum to receive stakeholder comments on two occasions:

- February 5, 2003 through February 10, 2003 on IFM/LMP issues; and
- March 6, 2003 through March 18, 2003 on Settlements Design Review Discussion Topics.

At stakeholders' request, the CAISO posted to its website a Comprehensive Issues Matrix ("CIM") on February 7, 2003 identifying 166 issues (http://www.caiso.com/docs/2003/03/07/2003030716335313992.pdf). On February 12, 2003, the CAISO hosted a stakeholder meeting to discuss the Stakeholder Online Forum results and comments, the Comprehensive Issues Matrix, MD02 implementation timeline, and RUC. The CAISO sent out a Market Notice on March 14, 2002 providing stakeholders with the opportunity to submit comments and any additional proposals that had not previously been considered. The CAISO indicated that it would consider the comments when finalizing the market redesign proposal that it intended to file with the Commission. The CAISO received comments from seven stakeholders and posted them to the CAISO's website.

### 4. Phase II and Phase III Settlements Design Review Meeting

The CAISO presented its Phase II and Phase III Settlements Design to stakeholders on March 4, 2003.[15] This meeting included an overview of the settlements system redesign. The stakeholders identified 24 Discussion Topics that required further clarification by the CAISO. Subsequent to the meeting, the CAISO has provided clarification on all but two of these topics, which will be addressed in a white paper and through the CRR studies.

### 5. Integrated Forward Market "Bid-to- Bill" LMP/CRR Stakeholder Meetings

The CAISO conducted stakeholder meetings from April 1-4, 2003 to discuss the long-term market design elements. Prior to the meetings, the CAISO posted to its website three white papers for stakeholder review. The white papers included: (1) Bidding Activity Rules, (2) Residual Unit Commitment Under MD02, and (3) Treatment of Self Schedules Under MD02. The first two days were dedicated to presenting the elements of the Integrated Forward Market and providing examples of different scheduling and bidding scenarios. For each example, the CAISO discussed how the process would proceed from the initial submission of a bid in the forward markets, through real-time, and finishing in Settlements. During the last two days, the CAISO presented its second LMP price dispersion study, discussed LMP and CRR issues, and discussed the CAISO's proposed resolution of outstanding issues. Throughout the four days of meetings, the CAISO responded to stakeholders' questions and concerns.

### 6. Publication of the Revised Comprehensive Market Design Proposal

In preparation for CAISO Governing Board discussions and a decision on the MD02 proposal, the CAISO posted on its web site a "Final Draft" of the current Proposal prior to the June 6, 2003 Board meeting and a slightly revised "Final Redline" version prior to the June 26 Board meeting. Both Board meetings received public comment on the published proposals and related issues. The Proposal being filed today is a lightly edited version of the Final Redline version approved by the Board, which incorporates a few clarifications and reflects the Board's direction on certain design elements requiring further development with stakeholders (discussed below).

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[15] Prior to the Settlements meeting, the CAISO posted to the Stakeholder Online Forum four Discussion Topics that required stakeholder input. Additionally, the CAISO conducted two conference calls on March 12th and 20th for further discussion and clarification of the posted topics.

### D. The CAISO's Request for Proposals

The CAISO began formulating the various components of the IFM/LMP RFP on August 2, 2002. Part of the development of the IFM/LMP RFP included external JAD sessions and internal Design Walkthroughs in order to flesh out design issues that required resolution prior to releasing the IFM/LMP RFP. On February 28, 2003, the CAISO released the IFM/LMP RFP to pre-qualified vendors. All pre-qualified vendors submitted bids by the March 26, 2003 deadline. The CAISO has now completed its evaluation of these bids and selected its preferred vendor for the IFM/LMP system.

The CAISO has incorporated flexibility into the IFM/LMP RFP to allow for further discussion on certain design elements, such as CRR allocation, that do not need to be fully resolved prior to software procurement. The CAISO identified these elements in the CIM that has been shared with stakeholders. Thus, the CAISO can proceed to execute a contract and develop the software and systems required to implement the Proposal upon receiving Commission approval of the Proposal, without running the risk of having to modify the contract based on the outcome of these parallel discussions.

To summarize, in preparing the IFM/LMP RFP, the CAISO has assumed that the Commission will approve, without significant modification, the market design embodied in the attached Proposal. The CAISO has, where possible, incorporated flexibility into the IFM/LMP RFP so that it can accommodate some deviation from the specifications in the attached Proposal. For example, the CAISO designed the IFM/LMP RFP to accommodate both a PJM-style and a NYISO AMP-type of local market power mitigation. However, if the Commission rejects any significant or material part of the Proposal, it would likely force the CAISO to go back and revise some aspect of the IFM/LMP RFP as part of the vendor contract negotiations. The additional time required to work through such a process would of course depend on the significance of the Commission's change, but could extend the MD02 implementation timeline.

## II. SUMMARY OF THE CAISO'S FILING

### A. The Amended Comprehensive Market Design Proposal

The amended Comprehensive Market Redesign Proposal set forth in Attachment A builds upon the May 1 Comprehensive Market Design Proposal (and the associated June 17, 2002 tariff language where appropriate), and incorporates modifications to certain of the market design elements made as a result of the stakeholder and internal activities described above. The amended

Proposal is built upon the same fundamental market elements that comprised the MD02 Phases II and III proposals in the May 1 Filing.[16]

The CAISO stresses that the Commission must evaluate the Proposal as an integrated package. The market design that the CAISO implements must be comprehensive, internally consistent, practical and cost-effective. Further, it must encourage participation by suppliers and, critically, must provide adequate protections to consumers against the exercise of system and local market power.

The CAISO requests that the Commission approve the market design encompassed in the Proposal contained in Attachment A in its entirety. The proposed design elements will correct the flaws in the CAISO's current market design and, in conjunction with the successful completion of activities now in progress at the State level, will lead to a well-functioning electricity market structure that benefits all consumers in California.

The remainder of this section summarizes the MD02 design elements as contained in the Proposal, and indicates the corresponding paragraph numbers of the Proposal where they are specified in greater detail. [17]

1. **Must Offer Obligations** (paragraphs 1-4 of the Proposal). The MD02 design assumes that the existing west-wide Real-Time Must Offer Obligation ("MOO"), which implies an obligation for long start time units to be available for Day-Ahead commitment, will be retained as a permanent feature of the CAISO marketplace. Further, the CAISO proposes to extend the MOO to the Day-Ahead and Hour-Ahead markets and Residual Unit Commitment ("RUC"). The Day-Ahead MOO is appropriate to prevent physical withholding and will facilitate the transition to a new market paradigm.

2. **Integrated Forward Market ("IFM") Based on LMP** (paragraphs 5-75 of the Proposal). The CAISO proposes to implement, in the Day-Ahead and Hour-Ahead markets, simultaneous congestion management and an energy market on a nodal basis, as well as the procurement of A/S on an area basis within the CAISO Control Area. The CAISO proposes to use a Security Constrained Unit Commitment ("SCUC") algorithm to run the integrated energy and congestion management markets, procure Ancillary Services and perform unit commitment, based on multi-part supply bids (Start-Up, Minimum Load, incremental energy curve, and a capacity reservation bid for A/S). The CAISO will use a detailed model of the CAISO grid to adjust submitted preferred schedules to mitigate congestion, ensure local reliability and, as a result, produce feasible

[16] Attachment B contains a chart identifying the major modifications that the CAISO has made to the Comprehensive Market Design Proposal it filed on May 1, 2002.

[17] An Index to Major Design Features is attached hereto in Attachment E.

forward schedules and congestion prices based on the differences between marginal energy prices at each node of the grid. With this change, the CAISO will eliminate the zonal congestion management approach that exists today, as well as the market separation rule. The proposed design will allow Scheduling Coordinators ("SCs") to self schedule loads and supply resources, and will allow commercial energy trading at a few key "trading hubs." The integrated A/S markets will procure Operating Reserves (Spin and Non-Spin) and Regulation (Regulation Up and Regulation Down as today). Under the CAISO's proposal, suppliers, including Participating Loads that respond to CAISO dispatch instructions, will be settled at nodal prices, whereas load will be settled at aggregated prices based on the service territories of the three Original Participating Transmission Owners ("PTOs").

3. **Congestion Revenue Rights ("CRRs")** (paragraphs 76-97 of the Proposal). CRRs will allow market participants to hedge the risk of congestion charges in a manner consistent with the LMP congestion management design. The CAISO proposes to allocate CRR Obligations to all loads in the CAISO control area that pay the embedded costs of the transmission grid. The CAISO intends to allocate CRRs in sufficient quantities to protect control area loads fully from congestion charges, if such quantities are determined to be simultaneously feasible. The CAISO will offer CRRs for any transmission capacity remaining after the initial allocation process in an auction open to all qualified participants. Allocated CRRs will follow load in the event that any end-use consumers switch to a different LSE. The demand side of initially balanced CRR schedules will have a scheduling priority in the Day-Ahead market. The CAISO proposes to release CRRs on a two-year rolling basis and on a short-term monthly basis. Sponsors of new transmission capacity will receive CRRs for such capacity provided the sponsor of the new capacity does not recover its investment costs through the CAISO's transmission access charge.

4. **Residual Unit Commitment** (paragraphs 98-113 of the Proposal). Because the outcome of the IFM is based on SC schedules and bids, it may result in a total scheduled quantity of energy that is substantially below the CAISO's forecasted load. The RUC reliability commitment procedure, which is featured in the designs of all the eastern independent system operators, would evaluate whether final forward schedules include sufficient on-line resources to meet the CAISO's demand forecast for the operating day or hour. If not, the CAISO would commit enough additional units to ensure that on-line capacity can meet forecast load. Supplies committed under RUC would be guaranteed recovery of Start-Up and Minimum Load costs (that would be netted against market revenues just as in the eastern markets). In addition, such suppliers would receive a bid-based availability payment if the energy from their capacity is not

scheduled or dispatched in the Hour-Ahead or Real-Time markets or the capacity is not sold in the A/S market. RUC cost allocation will follow generally accepted cost causation principles. Specifically, Day- Ahead RUC charges will be allocated to metered load that was not scheduled in the Day-Ahead IFM, and Hour-Ahead RUC charges will be allocated to metered load that was not scheduled in the Hour-Ahead IFM.

5. **Hour Ahead and Real Time Markets** (paragraphs 114-122 of the Proposal). Based on stakeholder input, the CAISO is proposing to close the Hour-Ahead market at T-120 (120 minutes before the start of the operating hour), publish final Hour-Ahead schedules at T-90, and allow 30 minutes for re-bidding before the close of submissions to the Real-Time market at T-60.

   The CAISO has been developing changes to the Real-Time market that will be implemented as part of Phase I-B of MD02. The basic Phase I-B elements were approved by the Commission in its July 17 Order and modified in subsequent orders. On July 8, 2003, the CAISO filed Phase I-B Tariff language with the Commission in a separate filing. The Real-Time market changes are integral features of the MD02 package and, with one exception, are not modified or otherwise affected by the design elements discussed in the Proposal. The one exception is that, upon implementation of LMP, the CAISO will introduce the Full Network Model into the Real Time Security Constrained Economic Dispatch, thereby initiating nodal pricing in Real-Time, as well as in the forward markets. This change is essential to ensure consistent allocation and pricing of transmission across different market time frames.

6. **Scheduling and Settlement of Loads** (paragraphs 62-65 and 123-129 of the Proposal). A crucial feature of the LMP market design is the geographic granularity used for scheduling and settling loads. The CAISO recognizes the equity concerns regarding potentially large LMP cost impacts on loads in constrained areas. Accordingly, in the present filing the CAISO proposes that: (1) loads within the CAISO control area that are not served under Existing Transmission Contracts ("ETCs") will schedule, bid and settle using a scheme of three large aggregation areas based on the CAISO's three original participating transmission owner service territories, *i.e.*, Pacific Gas & Electric ("PG&E"), Southern California Edison ("SCE") and San Diego Gas & Electric ("SDG&E"); (2) the aggregation scheme will apply to municipal and direct access loads as well as to loads served by the investor-owned utility distribution companies; (3) loads will not be allowed to opt out of the aggregation scheme. These three elements will address concerns that loads at low-price nodes will opt out and drive up the average aggregation prices, thereby undermining the intent of the aggregation scheme. In addition, to facilitate demand response, the CAISO will pay appropriate nodal prices to

Participating Loads (demand-side resources) for the amount of their Real Time curtailment in response to CAISO dispatch instructions.

7. **Bid Mitigation for Local Market Power** (paragraphs 130-146 of the Proposal). The Proposal includes effective Local Market Power Mitigation ("LMPM") measures in both the forward and the Real Time markets. The CAISO needs more effective LMPM measures than exist today in conjunction with implementation of LMP. The CAISO's primary LMPM proposal is based on the design currently being used by PJM. PJM's LMPM measures have worked effectively for many years and should provide the CAISO with sufficient protections against the exercise of locational market power by suppliers. The proposed primary LMPM proposal is largely consistent with the general approach advocated by the CAISO's independent Market Surveillance Committee ("MSC") in its May 29, 2003 opinion on local market power mitigation (see Attachment D hereto). In the event the Commission does not deem the CAISO's primary PJM-based LMPM proposal to be appropriate for the CAISO, the Commission should approve the CAISO's less effective alternative proposal which uses the Automatic Mitigation Procedure ("AMP"). The CAISO's AMP-based alternative proposal would utilize conduct and market impact thresholds equal to the lower of $10/MWh or 20 percent above the unit's Default Bid price and relevant market clearing price, respectively. Because LMP provides an incentive and opportunity for generators to exercise locational market power and increase nodal prices artificially, it is imperative that the Commission approve more effective local market power mitigation measures in conjunction with implementation of LMP.

8. **Existing Transmission Contracts** (paragraphs 66-70 of the Proposal). As the Commission is well aware, the CAISO has struggled with the problems caused by existing transmission contracts ("ETCs") since start-up. In particular, the CAISO's practice of Day-Ahead "reservation" of capacity for ETCs has resulted in "phantom" congestion in the forward markets that does not exist in Real-Time. Under the CAISO's proposal, ETCs will continue to have their traditional scheduling priority in the Day-Ahead IFM, but the CAISO will not reserve any additional transmission for them beyond what is scheduled in the Day-Ahead IFM. This will eliminate the source of the phantom congestion. ETC schedule changes in the Hour-Ahead IFM will have priority over other Hour Ahead submissions and will be accommodated, but only to the extent they do not require modification to final Day-Ahead schedules. To the extent any Hour-Ahead ETC submission cannot be fully accommodated in the Hour Ahead IFM, it will be accommodated in Real-Time. The CAISO will accommodate these and any additional Real-Time ETC changes (consistent with their rights) through Real-Time re-dispatch of resources. ETC schedules will generally be subject to the appropriate Real-Time charges associated with the

market to which they are submitted, including congestion charges and uninstructed deviation penalties. In addition, the CAISO proposes that PTOs (or another designated and capable SC) be responsible for ensuring on a day-to-day basis that submitted ETC schedules comply with the contractual rights of the ETC rights holders. Because these changes to current practice with respect to ETCs may expose PTOs or other SCs to additional costs, the CAISO requests that the Commission make it clear in its order on the CAISO's Proposal that these entities will be permitted to recover their prudently incurred costs associated with managing ETCs. This position is contemplated by the Commission in its SMD NOPR.

9. **Metered Subsystems** (paragraphs 147-157 of the Proposal). The MD02 proposal will grant Metered Subsystems ("MSS") the option of fully participating in the CAISO's markets and being treated like any other market participant. However, to the extent a MSS operator wants different treatment in recognition of its unique features and functions, the CAISO will accord them such treatment.

### B. The Continuing MD02 Process

The filing of the current Proposal represents an important next step in the reformation of the CAISO's markets. Notwithstanding the importance of this filing, there remain a number of equally important tasks that must be performed prior to implementation of the MD02 design. These tasks include the following:[18]

- Finalizing the CAISO's internal CRR study, working with the CPUC and initiating the CRR allocation process;
- Resolving cost allocation and other issues related to the CAISO's proposed procedure for honoring ETCs;
- Aligning, to the extent practical and necessary, the final CPUC procurement rules for the IOUs with the Commission-approved MD02 design; and

[18] The CAISO also recognizes that, in the future, once the form and function of the other RTOs in the western region are finalized, the CAISO may have to adapt its markets or its procedures to better complement the larger regional market structure. The CAISO is already working toward the creation of seamless western markets through its participation in the Seams Steering Group – Western Interconnection ("SSG-WI"), and is therefore cognizant of the flexibility that must be designed into the MD02 implementation to allow for improved integration across the region. In this regard the CAISO and the SSG-WI are closely following the progress of some of the (mainly LMP-based) eastern ISOs in developing solutions to inter-ISO/RTO integration issues. Although this subject is vitally important for the long term, the implementation of the CAISO's redesign proposal need not wait for the other RTOs to finalize their designs, and therefore this Proposal does not discuss this matter further.

- Identifying and aligning the market and scheduling rules that best accommodate both pre-existing as well as going-forward bilateral sales that occur outside of the CAISO's markets.

As set forth in CAISO management's memorandum to the CAISO Governing Board dated June 20, 2003,[19] as well as the motion passed by the Board at its June 26, 2003, meeting, the Board directed management to continue to work to address these issues and processes. Each of these tasks and processes is discussed further below.

### 1. The CRR Study and Allocation Process

The CAISO is currently in the process of completing the initial stages of its CRR study. The purpose of this study is to determine the amount of CRRs that will be available for allocation to LSEs on behalf of CAISO Control Area loads and to offer at auction to market participants. The CRR study entails developing a complete and accurate model of the CAISO transmission system, as well as determining the likely amount and pattern of load and generation within the CAISO system. The model must also determine and reflect the impact of ETCs on the availability of CRRs. Such a model will enable the CAISO to determine the quantities of CRRs that will be simultaneously feasible and, thus, available to market participants.

In its April White Paper regarding development of a "Wholesale Power Market Platform," the Commission contemplated an important role for regions and states (as represented in the "Regional State Committees") in the CRR allocation and auction process. In order to acknowledge and accommodate the important role of the State of California with respect to CRRs, the CAISO will soon be meeting with the CPUC to develop the process for determining CRR allocation issues. This will require that the CAISO coordinate closely with the CPUC and with non-CPUC jurisdictional entities over the next several months in completing the CRR study, interpreting the results of the study and its implications for CRR availability and conducting the CRR allocation process. The CAISO and the CPUC will work together to determine the appropriate parameters and assumptions of the CRR study. In addition, if the initial modeling runs indicate that there may not be enough CRRs to fully hedge LSEs from anticipated congestion costs – an outcome that may arise depending on the ultimate approach to accommodating and modeling ETCs – the CAISO will work with the CPUC to determine appropriate adjustments to the model and the allocation process so as to provide a sufficient hedge to LSEs. The CAISO and CPUC will continue to update the Commission on the progress of these efforts in the monthly MD02 status reports.

[19] These documents are contained in Attachment C hereto.

### 2. The Proposal for Honoring ETCs

Section III.H of this document discusses the reasons why the CAISO is proposing an approach for honoring ETCs that differs significantly from the approach described in the May 1 Filing. Without reiterating those arguments or the details of the CAISO's ETC proposal here, the proposal consists of three main elements: (1) principles for accommodating ETC schedules in the CAISO's markets; (2) responsibility for ensuring that ETC schedules comply with the contractual rights specified in the particular contracts; and (3) responsibility for payment of CAISO charges associated with ETC schedules.

As elaborated in Section III.H of this filing, certain aspects of the proposal are so fundamental that their basic design cannot be altered without undermining the objectives of the proposal. In particular, central to the proposal is the principle of honoring the current ETC scheduling priority and fully accommodating ETC rights to use the transmission system, without continuing the current practice of reserving of transmission capacity in the Day-Ahead for ETCs that are not scheduled Day-Ahead (item (1). Another central principle is to relieve the CAISO of its current primary role of managing ETC rights on a day-to-day basis, which involves for example, ensuring that ETC schedules comply with their contractual rights (item (2). Finally, the CAISO believes it is essential to process ETC schedules through the CAISO's settlement system in the same manner as the schedules of other grid users (an aspect of item (3)).

In any event, the CAISO acknowledges that many details of the ETC proposal remain to be specified, and the CAISO intends to work with the affected parties to develop the ETC design in the most efficient and acceptable manner possible, in accordance with the principles stated above. For example, with regard to day-to-day verification of compliance of ETC schedules with their contractual rights, the CAISO believes that the PTOs are in the best position to do this. At the same time, the CAISO understands that in some instances the PTOs have transferred ETC scheduling responsibility to the ETC rights holders themselves. In those cases, it may be appropriate to transfer this responsibility to another designated SC, subject to periodic audit.

Similarly, with regard to responsibility for CAISO charges, the CAISO Tariff clearly allocates charges to SCs based on their schedules and meter data. The CAISO is willing to work with the parties to develop mechanisms – such as special SC ID numbers and inter-SC trades – that will facilitate an allocation of cost responsibilities that is acceptable to the parties while still being consistent with the CAISO settlement rules and systems.

### 3. MD02 and Resource Adequacy

As the Commission is aware, the exercise of market power, the lack of adequate infrastructure and the lack of forward contracting between buyers and sellers contributed significantly to the electricity crisis of 2000-2001. As a result, the State of California has initiated a number of efforts to create a resource adequacy framework for California. The centerpiece of those efforts is the CPUC's procurement proceeding through which the CPUC will establish the rules and requirements for forward procurement of supply by the IOUs it regulates. Each party to the proceeding has already filed direct testimony and the CPUC will hold hearings beginning July 21st. The CPUC anticipates issuing a final order in the procurement proceeding later this year.

The CAISO is actively engaged in the procurement proceeding. Among other issues, the CAISO has advocated that the CPUC adopt formal planning reserve requirements for the IOUs and a formal process that would provide for regular (monthly and annual) validation of IOU compliance with the procurement and reserve requirements. In addition, the CAISO has recommended that the CPUC specifically assess, and establish requirements for, the deliverability of capacity resources procured by the IOUs. Absent such a requirement, the CAISO is concerned that resources procured by the utilities may fulfill their obligations under the CPUC's rules yet not effectively be available to the system. The CAISO also recommends that the CPUC ensure that resources procured by the utilities be offered to the CAISO in the forward market for possible commitment by the CAISO to serve forecast load. The CPUC will evaluate these proposals as part of its proceeding to determine if they are needed.

Once final resource adequacy-related rules are established by the State, the CAISO will evaluate the need for the CAISO to make conforming changes to its market design. Because the CPUC is not expected to issue a final procurement rule until late this year, the CAISO must wait until early in 2004 to undertake a review of the procurement rules and determine if any refinements to the MD02 proposal are necessary. The CAISO will inform the Commission about developments in the State's resource adequacy activities in its monthly MD02 status reports.

### 4. LMP and Bilateral Contracts

One key issue that has arisen in the context of finalizing the Proposal is the impact of the MD02 design on the scheduling of, and congestion costs related to, bilateral power contracts. Specifically, the California Energy Resource Scheduler ("CERS") has raised concerns that the implementation of an LMP-based market design will have an adverse impact on the long-term contracts entered into by the California Department of Water Resources ("CDWR") on behalf of retail consumers during the 2000-2001 electricity crisis. While the issue is broader than the impact of MD02 on the CDWR contracts, the circumstances surrounding those contracts highlight the issues involved.

CDWR presently has approximately 10,000 MW of capacity under contract, roughly half of which is referred to as "must take" (although "take-or-pay" would be more accurate), while the other half is "dispatchable." The "must-take" contracts, representing arrangements with four suppliers, provide that the State must pay for predetermined quantities of energy which the supplier can deliver under the contract at its choice of a number of delivery points. One contract in particular provides for delivery at any point on the CAISO system at the seller's discretion, while the other three provide for delivery at any point within either SP15 or NP15.

CERS' concerns regarding the impact of LMP on the CDWR contracts are twofold. First, CERS is concerned that LMP will result in increased congestion costs for the State contracts, hence increased costs to ratepayers. Under the current zonal market design, congestion cost exposure under the contracts is limited because the congestion impact is largely Intra-Zonal and, as such, the congestion costs arise only as a result of Real-Time re-dispatch and then are borne by all loads within the respective Zones. CERS is concerned that, under a LMP-based regime in which suppliers are paid nodal prices based on forward schedules, suppliers will be able to select delivery points that will maximize congestion counter-flow revenues to themselves and increase costs to load by injecting energy at high-cost nodes on the system and delivering to the buyer at low-cost nodes. CERS argues that such an outcome will lead to significantly increased congestion costs for California consumers.

Second, CERS is concerned that the increased congestion costs under an LMP-based system will disadvantage the long-term CDWR contracts by making them less economic. In such circumstances, the IOUs, to whom the contracts have been allocated by the CPUC, will not dispatch such energy contracts to serve retail load, but will instead sell the power off in the market. According to CERS, such an outcome will defer CDWR's revenue recovery and result in higher rates in the future. Both of these issues are further discussed in the attached June 20th CAISO Governing Board memorandum.

The CAISO acknowledges the concerns raised by CERS and other bilateral contract holders. The CAISO Governing board recognized the legitimacy of this transitional issue by directing CAISO Management to continue to work with the affected parties towards resolution of this issue prior to implementing LMP. The CAISO presently sees two promising avenues for resolution of this issue. The first, as detailed in the June 20th Board memorandum, is the mechanism of Inter-Scheduling Coordinator ("Inter-SC") trades (*i.e.*, bilateral trades that occur outside of the CAISO's markets but which may be scheduled in the CAISO's markets to facilitate allocation of CAISO charges between the contracting parties without affecting IFM results in any way). The second is the use of CRRs to hedge congestion cost exposure. The CAISO will continue to keep the Commission apprised of developments in this area.

### C. Revenue Adequacy for Supply Resources

As the Commission is aware, continued uncertainty regarding the ultimate design of the CAISO's markets contributes to the poor climate in California for investment in electric infrastructure. While resolution of the CAISO's market design is generally viewed as highly desirable, concerns have been raised about whether the present Proposal will be sufficient in and of itself to improve the climate significantly. Those raising the concerns argue that the Proposal does not ensure an adequate revenue stream to ensure the commercial viability of supply resources, particularly in light of: (1) the fact that there does not exist a formal capacity obligation or CAISO-operated capacity market, and (2) the proposed local market power mitigation mechanisms and levels in the CAISO-operated spot markets. These concerns are unfounded.

### 1. Revenue Adequacy in the Spot and Bilateral Markets

In any market, there must be sufficient opportunities for suppliers to recover their costs, both fixed and variable. Absent sufficient opportunities to recover costs, suppliers will exit the market, thereby leading to the possibility of supply deficiencies, higher prices and/or product rationing. In the case of California's electric industry, "revenue adequacy" concerns have been raised regarding both the existing market and the CAISO's proposed redesign, specifically with regard to recovery of fixed costs. To assess (and address) those concerns, the CAISO has reviewed the MD02 design – as well as the context in which MD02 will be implemented – from this perspective, and has determined that there will be sufficient revenue opportunities available to support fixed cost recovery.

First, the proposed spot market pricing mechanisms are more than sufficient to cover any resource's incremental costs. In addition to receiving the nodal market-clearing price, resources participating in the CAISO's markets are also eligible to be compensated for their start-up, minimum load and emissions costs. Under MD02, suppliers will have the flexibility to submit either cost-based or market-based start-up and minimum load cost bids. Furthermore, suppliers participating in the A/S markets may submit market-based capacity bids and receive capacity payments. The CAISO is one of the few independent system operators that provides markets for four types of Ancillary Services*, i.e.,* Spinning Reserve Non-Spinning Reserve, Regulation Up and Regulation Down.[20] The CAISO paid out approximately $ 85 million in capacity payments for these services in 2002. Under MD02, the CAISO will continue to provide capacity payments to A/S suppliers.

In addition to these opportunities in the daily markets, the CAISO designates certain resources to be Reliability Must-Run ("RMR") Generation on the basis of local area reliability requirements. RMR units are required to be available to the CAISO for dispatch to maintain reliable operation in local areas of

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[20] It is important to note that under MD02 the bid caps in the CAISO's A/S markets will remain at $250/MW/hr. PJM currently has a $100/MW cap on regulation bids and a $7/MW cap on spinning reserve bids.

the grid. To compensate RMR units for being available, the CAISO pays a certain portion of their fixed costs. The CAISO paid out more than $260 million dollars in such capacity-related payments to RMR Generation in 2002, and that number is estimated to increase to $360 million in 2003 (as a result of certain old inefficient units shifting to RMR Condition 2 status).[21]

Second, and perhaps most importantly, in 2001 the State of California entered into more than $40 billion worth of long-term power contracts to cover the three IOUs net short load requirements. During peak periods these contracts – which provide capacity payments to suppliers – account for approximately 70 percent of the IOUs' net short load requirements, leaving the balance to be supplied by short-term bilateral contracts, utility-retained generation and spot purchases. Many of the State contracts run through the 2010-2011 timeframe. Thus, during the first several years of MD02 implementation, suppliers of these contracts will continue to receive a substantial stream of capacity payments for supplying a substantial portion of IOU load under the State contracts.[22]

The undeniable fact is that an overwhelming majority of load in California is covered by long-term contracts that provide adequate capacity payments to suppliers. Moreover, the level of activity in CAISO spot markets has been minimal for some time and is expected to remain so. During 2002, generally only one-to-two percent of the IOUs' net short (three percent in September 2002) was met in the CAISO Real-Time market. On the peak hour in 2002, only nine percent of the IOUs' load was met through a combination of short-term bilateral contracts and Real-Time purchases. Suppliers should not rely on a small CAISO spot market to recover large portions of their fixed costs. Such a strategy is particularly inappropriate given the fact the 2000-2001 crisis drew everyone's attention to the problem of over-reliance on spot markets and the need for LSEs to rely predominantly on long-term bilateral contracts. MD02 is designed explicitly to support this objective.

Third, in November 2002, the CPUC authorized the IOUs to resume purchasing power for their customers through short-term bilateral contracts commencing January 1, 2003. For the last six months, the IOUs have been managing their own supply portfolios based on least-cost procurement and dispatch protocols approved by the CPUC. Under these rules they have been purchasing some of their energy and capacity in advance of their real-time needs utilizing portfolio and risk management strategies. These short-term IOU

[21] Under Condition 2 RMR status, the RMR unit completely foregoes market opportunities in exchange for capacity payments that fully cover its fixed costs. If all RMR units were to convert to Condition 2 status, the CAISO estimates that annual fixed revenue requirements would exceed $500 million.

[22] It is important to note that, while suppliers may point to the absence of a formal capacity market in California as evidence of inadequate opportunities for fixed-cost recovery, the PJM Capacity Credit market is used by PJM utilities to meet only 0.3 percent of their capacity obligations in 2002. The balance of their obligations were met through bilateral contracts. See PJM State of the Market Report for 2002.

purchases provide yet another opportunity for suppliers to recover some of their costs**.**

Finally, the CAISO notes that the RUC element of the Proposal provides for an availability payment to suppliers whose capacity is committed by the CAISO, but not ultimately dispatched for energy or awarded A/S. This availability payment is based on the supplier's market-based bid, is paid as-bid for each MW of committed capacity, and is paid in addition to the guaranteed recovery of Start-Up and Minimum Load costs.

### 2. Local Market Power Mitigation and Revenue Adequacy

With respect to Local Market Power Mitigation ("LMPM"), the CAISO determined that the proposed measures, as complemented by other related mechanisms, reasonably balance the need for effective and appropriate mitigation of local market power with the cost-recovery concerns of those resources most likely to be mitigated under the CAISO's proposal. First, the CAISO proposes to allow resources mitigated under LMPM to collect the market-clearing price at their location, rather than be limited to collecting their mitigated bid price. Second, the proposed LMPM procedure limits both the circumstances under which such bids will be mitigated and the extent of such mitigation. In particular, the LMPM procedure will mitigate only that portion of the bid curve dispatched to resolve congestion that cannot be resolved with competitive bids.

The MD02 LMPM proposal provides additional provisions to ensure that mitigated resources are compensated fairly. For example, the CAISO's preferred (PJM-type) LMPM approach would allow a thermal unit to receive a 10 percent adder above its cost-based Default Energy bid when mitigated under LMPM, as a margin against potential inaccuracy of the unit's variable cost as calculated from its heat rate curve. Similarly, the CAISO's back-up (AMP-based) LMPM proposal would allow units to bid the lower of $9.99/MWh or 19.99 percent above their reference price before they would be subject to mitigation for local market power reasons. Finally, under the MD02 proposal, those resources that are frequently mitigated by the LMPM mechanism can (1) request to be designated as a Reliability Must-Run Generator (if qualified), (2) file with the Commission for cost-based rates, to ensure full recovery of all costs, or (3) request from the CAISO partial fixed cost recovery as a separate annual capacity uplift from the CAISO.[23] The CAISO submits that, under these circumstances, its LMPM proposal adequately addresses revenue adequacy concerns, especially given the emphasis on forward procurement of supply and minimal reliance on the spot markets.

[23] The third option is not part of the current Proposal but is an option the CAISO is willing to consider if it would result in the Commission approving the proposed PJM-style LMPM measures.

### 3. The State's Resource Adequacy Activities

From the beginning of the MD02 project, the CAISO has recognized that, beyond the redesign of its own markets, additional policies and actions by other entities are needed to stabilize the electricity supply situation in California. In particular, to achieve a stable, sustainable supply of electricity at reasonable prices, policy makers at the federal, state and local levels need to develop the institutional and regulatory framework necessary to create a favorable climate for infrastructure investment, including clear rules that will facilitate and attract such investment. The State of California is moving forward to establish that framework.

To that end, the CPUC proposes to establish, by the end of this year, rules to guide the procurement activities of the IOUs, who represent approximately three-fourths of the load in the State.[24] These rules will promote an integrated resource planning framework from which the IOUs can establish the need for and facilitate investment in generation, transmission and demand-response infrastructure. Most importantly, the CPUC's rules and the IOUs' plans will establish a foundation for future forward contracting between the IOUs and potential suppliers. Forward contracting is the primary vehicle through which investment occurs most readily because it creates the stable revenue stream necessary for investors to support new infrastructure investment.

The Commission has determined in its recent White Paper that the issue of resource adequacy should be addressed first by the states rather than by the independent transmission provider. Because the State of California is in the process of developing a formal resource adequacy plan and the CAISO is a fully engaged participant in that process, the Commission should not reject or defer ruling on any aspects of the CAISO's MD02 proposal on the grounds that the CAISO is not proposing a resource adequacy plan.

The CAISO's Proposal appropriately focuses on the redesign of the CAISO's congestion management function and spot markets, and provides adequate compensation to suppliers who participate in its spot markets, consistent with the design objective of moving most of the volume of energy transactions to a more forward time frame. The Proposal should therefore be viewed by the Commission as consistent with the vision set forth in the White Paper and, most importantly, sufficient in its provisions for supplier revenue adequacy.

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[24] The CPUC has ongoing a long-term procurement proceeding in Docket No. R01-10-024. In April 2003, the three IOUs submitted their long-term procurement plans, which will be the subject of a CPUC hearing in July, 2003. The CPUC has already (1) ordered the IOUs to meet all of their expected energy needs through 2003 and the first quarter of 2004, (2) allocated the State's long-term contracts among the three IOUs, (3) set guidelines on the volume of utility procurement that can be exposed in the spot market, and (3) set guidelines on the appropriate level of reserves based on input from the California Power Authority.

### D. The CAISO Proposes to Withdraw the Phase II and III Tariff Language Previously Filed

To facilitate the ongoing design process and to eliminate any unnecessary regulatory uncertainty, the CAISO requests that the Commission allow the CAISO to withdraw the tariff provisions for the Phase II and III market design elements that the CAISO submitted on June 17 and June 28, 2002. There have been numerous changes to the proposed market design since the Phase II and III Tariff language was filed, requiring significant revisions to that Tariff language. Withdrawal of the previous submissions will allow the CAISO to start fresh to develop updated Tariff provisions that reflect the current Proposal, which the CAISO proposes to submit after the Commission approves the current Proposal.

### E. The CAISO's Proposed Process for Filing the Tariff Language to Implement the MD02 Proposal

Assuming the Commission approves the Proposal without modifying any of the basic assumptions underlying the design, the CAISO proposes to submit detailed Tariff language 120 days prior to the effective implementation date of the new market design. Commission approval of this process in conjunction with approval of the Proposal will permit the CAISO to act expeditiously to finalize and execute contracts with vendors to commence development of the required software and systems.

## III. DETAILED DISCUSSION OF THE CAISO'S AMENDED COMPREHENSIVE MARKET REDESIGN PROPOSAL

### A. An Integrated Forward Market Based On LMP

The primary feature of the CAISO's proposed market redesign is a Day-Ahead and Hour-Ahead integrated forward market that involves the simultaneous optimization of congestion management, an Energy market, and Ancillary Services procurement based on LMP. *See* Section 2.2 of amended Comprehensive Market Design Proposal. With the proposed changes, the CAISO will eliminate the distinction between Inter-Zonal and Intra-Zonal congestion, eliminate the market separation rule and the balanced schedule requirement, and conduct a forward spot energy market integrated with congestion management. The proposed forward congestion management procedure will optimally procure generation and "balance" all generation, load, import and export schedules using a SCUC algorithm with an AC power flow model to enforce linear transmission constraints. *Id.* at Section 2.2. The power flow model the CAISO will utilize will include all buses and transmission constraints within the CAISO transmission grid and an electrically equivalent representation of the western grid outside of the CAISO Control Area. *Id.* at Sections 2.2.2 and 2.2.4.

The CAISO's proposed power flow model will produce LMPs at every bus in the network that incorporate the total value of Energy, transmission congestion and losses at each node on the CAISO grid. In other words, the CAISO will produce locational marginal Energy prices at the nodal level.

The CAISO will use a SCUC optimization routine to minimize the cost of meeting scheduled demand and clearing economic demand bids in the forward market subject to all transmission constraints and generator performance characteristics. *Id.* at Sections 2.2.1 and 2.2.2. The proposed LMP congestion management approach ensures that final schedules will be feasible with respect to all transmission constraints, as well as with generator ramping and other performance constraints.[25] Under the LMP scheme proposed by the CAISO, suppliers will be settled at the nodal level and load will be settled at three large, aggregated areas based on the Original Participating Transmission Owner service areas.[26] *See* Section 2.6 of the Proposal. Because LMP provides an incentive and opportunity for generators to exercise locational market power and increase nodal prices artificially, it is imperative that the Commission approves more effective local market power mitigation measures in conjunction with implementation of LMP.

### 1. LMP Is Both Necessary And Appropriate

The CAISO proposes to manage congestion and price Energy using LMP. LMP is the method that is currently used for managing congestion in the regional markets operated by PJM, the New York ISO ("NYISO") and ISO New England ("ISO NE"). Further, LMP is the Commission's preferred approach for congestion management. *See White Paper* at 7. Eastern markets have functioned effectively for many years with LMP. There is no reason why the California markets cannot also function effectively with LMP. Further, the CAISO's MSC has noted that many variants of LMP have been adopted around the world, and its usage in those markets has not caused significant difficulties.[27]

[25] In contrast, in Real-Time, the CAISO will utilize a Real-Time Security Constrained Economic Dispatch ("RTD") optimization program to procure imbalance energy and manage congestion simultaneously. RTD will initially be implemented in Phase IB using a zonal model. This represents a fundamental change from the current market design in which imbalance energy is procured from a merit order stack. Under Phase III, the RTD will minimize the Real-Time cost of imbalance energy determined from energy bids, subject to transmission interface, nomogram and resource capability constraints, and taking into account transmission losses. This will allow the CAISO to manage all Real-Time Congestion without dispatching resources out-of-sequence.

[26] However, Participating Load that responds to a CAISO dispatch instruction will be treated as generation and settled at the nodal level. *See* Section 2.2.10 of the amended Comprehensive Market Design Proposal.

[27] *See* "Comments on Locational Marginal Pricing and the California CAISO's MD02 Proposals", Market Surveillance Committee of the California ISO (April, 2003) ("MSC LMP Comments"). These comments are included with this filing as Attachment F.

Implementation of LMP will provide many important benefits to California including: (1) fixing the CAISO's existing flawed congestion management system, (2) enabling CAISO grid operators to operate the transmission grid more reliably and with greater transparency, (3) largely eliminating the "DEC" game (which is discussed *infra* in Section III.A.1.a.2) and other Enron-type games, and (4) providing transparent price signals to encourage investment in new generation and transmission and promote demand response.

As discussed in greater detail below, the benefits of a LMP pricing and congestion management scheme are significant. Most importantly, provided effective local market power mitigation measures are in place, the CAISO does not anticipate any significant increase in wholesale Energy costs as a result of implementation of LMP. As discussed *infra*, the CAISO proposes to settle load using average prices based on the load in three pricing areas. Further, the CAISO proposes to allocate CRRs to LSEs in an amount based on their historic load. *See* Section 2.3 of the amended Comprehensive Market Design Proposal. These financial rights should help insulate LSEs from congestion costs on the system. Further, there is the potential for reduced costs to consumers. LMP, by nature of the fact that it will more accurately price the true cost of using the grid, should result in a more efficient and effective dispatch, *i.e.*, a dispatch that enables more efficient generation to be dispatched and compete for limited transmission capacity. LMP eliminates the need for the CAISO to make out-of-sequence adjustments for Congestion. LMP prices are consistent with the system operator's actual dispatch of the least cost units. In addition, LMP-based markets benefit from the efficient price signals that LMP provides to those considering long-run investments in new generation, load management and other demand resources, as well as transmission upgrades that help eliminate congestion. The proposed forward and Real-Time optimization also will commit and dispatch resources more efficiently than current markets do, ensuring that LMP is the result of a least-cost dispatch of the resources available to the transmission system in a manner that recognizes the operational limitations of resources and constraints of the transmission system. Thus, loads can be served at the lowest total cost consistent with reliable operation of the system.

#### a. Problems With The CAISO's Existing Congestion Management System

The problems with the CAISO's existing congestion management process are well chronicled,[28] and there is no doubt that the existing congestion management system is not functioning effectively.[29] The CAISO's existing

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[28] *See* CAISO's Amendment No. 23 Tariff Filing, Docket No. ER00-555, filed November 10, 1999; CAISO's Amendment No. 42 Tariff Filing, Docket No. ER02-922, filed January 31, 2002; and CAISO's Amendment No. 50 Tariff Filing, Docket No. ER03-683-000, filed March 31, 2003.

[29] Indeed, the Commission previously has found such system to be "fundamentally flawed" and in need of replacement. *San Diego Gas & Electric Company v. Sellers of Energy and*

congestion management system is unwieldy, burdensome, costly to consumers, and subject to manipulation. It is problematic from both an operational and a financial perspective and results in unjust and unreasonable prices being borne by California consumers. As such, it is imperative that the existing congestion management system be replaced as soon as possible. Using a LMP congestion management process will resolve the operational and economic problems caused by the CAISO's existing congestion management process.

#### (1) The CAISO's Inability To Manage Intra-zonal Congestion In Advance Of Real-Time Presents Reliability Concerns

The CAISO currently employs a zonal congestion management model in which transmission constraints between zones are explicitly modeled. The existing scheme was based on the assumption that Intra-zonal congestion would be infrequent or insignificant, and that any Intra-zonal congestion could be managed without using the price of transmission service to ration use. This assumption has proven to be false. Because the CAISO's congestion management system does not model Intra-zonal transmission constraints and accepts schedules from SCs that are not physically feasible, the CAISO has no effective process for managing Intra-zonal congestion in the forward market. As a result, instead of managing Intra-zonal congestion the same way the CAISO manages Inter-zonal congestion, *i.e.*, by ensuring that schedules cannot cause congestion, the CAISO has been forced to accept forward schedules that create congestion and attempt to manage such Intra-zonal congestion in Real-Time. This is a difficult and burdensome process that demands a disproportionate share of grid operators' time, forces them to scramble in Real-Time to keep the grid running reliably, and impinges on their other responsibilities.[30]

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*Ancillary Services into Markets Operated by the California Independent System Operator and the California Power Exchange*, 93 FERC ¶ 61,121 at 61,365-66 (2000); *see also California Independent System Operator Corporation*, 90 FERC ¶ 61,006 at 61,011-14 (2000).

[30] In his Affidavit concerning the importance of managing Intra-zonal congestion before Real-Time, submitted as Attachment E to the CAISO's Amendment No. 50 Tariff filing in Docket No. ER03-683-000, James McIntosh, the CAISO's Director of Grid Operations detailed the nature and magnitude of the operational problems caused by the CAISO's existing process for managing Intra-zonal congestion. Currently, the CAISO accepts all transmission schedules in the Day-Ahead and Hour-Ahead timeframes without determining whether the schedules are feasible over Intra-Zonal transmission paths. This creates the potential for overloads in portions of the grid in Real-Time because, if all schedules are not feasible, more energy may be scheduled on a portion of the grid than can be accommodated reliably. Overloaded components jeopardize the reliability of the transmission grid, as well as general public safety. Prudent power system operations demand that all possible steps be taken to prevent components from overloading and, if that effort fails, then to reduce overloads immediately as they occur. While prudent practice dictates that steps be taken in advance to avoid the overload, the CAISO cannot take such steps because it has no means of managing Intra-zonal congestion prior to Real-Time. Accordingly, once the CAISO identifies an overload in Real-Time, it must act immediately to remedy the problem. This generally means that the CAISO must request and accept Real-Time decremental energy bids, *i.e.*, "DEC" bids, to relieve the constraint. The need to manage Intra-zonal congestion imposes a

### (2) The Existing Congestion Management System Facilitates The “DEC” Game

The CAISO’s inability to manage Intra-zonal congestion in advance of Real-Time also has adverse economic effects. In general, the existing zonal scheme enables participants to cause congestion, the cost of which is not borne by the participants themselves, but by all load within the zone. Such a result inappropriately shifts congestion costs to consumers and creates poor price signals and market incentives. In addition, the zonal pricing regime creates an environment in which suppliers can play the so-called “DEC” game.[31]

Once the CAISO identifies “DEC” bids that it can utilize to relieve an Intra-zonal constraint, the issue becomes one of economics. In that regard, when Intra-zonal congestion occurs, *e.g.*, when a transmission line has an outage creating an unexpected and temporary constraint, the constraint may be localized and there may be only one generator located on the export side of the constraint.[32] That generator can exercise locational market power because it

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significant burden on the CAISO’s Real-Time operations staff. Specifically, the process demands the immediate, concentrated attention of a number of CAISO staff, detracts from their primary responsibilities, and can occupy staff time for several hours, depending on the load, outage and generation conditions that create the overload.

[31] Indeed, the MSC recognizes that there are inefficiencies in the existing market design that enable traders to engage in undesirable strategies such as the “DEC” game. Attachment F at 2.

[32] The Affidavit of Dr. Eric Hildebrandt, which was submitted as Attachment P to the May 1 Filing, explained how suppliers have been exercising local market power under the CAISO’s existing market rules and provided specific examples of how suppliers have been playing the DEC game. Specifically, because of their local market power, certain suppliers have been called out-of-sequence (*i.e.,* not in the economic merit order of the CAISO BEEP stack) and paid prices for decremental Energy that are significantly lower than the Real Time Imbalance Energy MCP and the suppliers’ own marginal costs for production of such decremental Energy. In fact, suppliers with local market power routinely submit negative decremental bids that are far in excess of any variable production costs suppliers incur in connection with reducing a Generating Unit’s output (*i.e.,* “DEC-ing” such a unit), and the CAISO is often forced to accept such bids because competitive alternatives are not available. This results in the CAISO paying the supplier to reduce Energy output. Dr. Hildebrandt also submitted an Affidavit in Docket No. ER03-683-000 in support of the CAISO’s Amendment No. 50, wherein the CAISO proposed more effective measures to mitigate the exercise of local market power pending implementation of LMP. That Affidavit identified additional examples of local market power being exercised and suppliers playing the so-called “DEC game.” The CAISO also notes that in Docket No. EL02-51, the California Electricity Oversight Board filed a complaint against numerous generators alleging that such generators were exercising market power by submitting anticompetitive negative “DEC” bids. The EOB complaint identified examples of suppliers’ submission of 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).

knows that the CAISO must accept its adjustment bid regardless of the price because there is no competition. In these circumstances, the generator that is in a position to relieve congestion has the incentive and the means to engage in the "DEC" game, *i.e.*, create additional congestion for the sole purpose of increasing the amount it may charge for congestion relief, *i.e.*, "DEC-ing its unit(s).[33] In other words, a supplier can game the system by creating congestion itself for the sole purpose of inflating its profits by offering to relieve such congestion at an artificially high price. The Commission previously has recognized that this is a fundamental flaw in the CAISO's congestion management system[34] and, recently, in addressing the CAISO's Amendment No. 50, adopted mitigation measures to address this problem on an interim basis pending implementation of LMP and the full network model.[35]

#### b. A LMP Congestion Management Scheme And Enforcement Of A Full Network Model Will Enable The CAISO To Manage Congestion More Effectively and Efficiently And To Deter The "DEC Game"

The LMP-based congestion management scheme proposed by the CAISO should effectively address and reduce both the over-scheduling of generation (and the concomitant creation of Intra-zonal congestion) and opportunities for the "DEC" game. *See* Attachment F at 5. The CAISO's proposal attempts to assure that all schedules are feasible with respect to all transmission constraints, as well as generator performance limitations. The distinction between Intra-zonal and Inter-zonal congestion will be eliminated. In other words, the system will not accept infeasible Day-Ahead schedules because the elimination of the zonal model removes the need to treat them separately. This also means that generator location and "effectiveness" will be considered when resolving congestion; on the other hand, the zonal model ignores the ability of some units to be more effective than others when attempting to reach a congestion solution.

The feasible schedule requirement associated with LMP, the Full Network Model ("FNM") and SCUC procedures should generally make it easier for Real-Time grid operations staff to run the grid and should promote increased system reliability. *Id.* Feasible LMP-based schedules enhance reliability because system operations and the LMP schedules and congestion management rely on the

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[33] In its order on Amendment No. 23 to the CAISO Tariff, the Commission previously has recognized that in California there are conditions where no effective competition exists to relieve certain transmission constraints giving rising to Intra-Zonal Congestion, and there is no market discipline on the price bid by a Generator possessing the ability to reduce its Schedule (*i.e.,* DEC its unit). *California Independent System Operator Corporation*, 90 FERC ¶ 61,006 ("Amendment 23 Order") at 61,011.

[34] Amendment 23 Order at 61,013.

[35] *California Independent System Operator Corporation,* 103 FERC ¶61,265 (2003).

same bid-based dispatch. Stated differently, system operations and market operations are inseparable in the short-run time frame in which grid use must be coordinated by a central operator to maintain reliability. More than any other market design, a LMP-based model is consistent with this principle. Further, because LMPs are consistent with a security-constrained dispatch that relieves congestion, while keeping the system in balance, market responses to these prices will tend to support, rather than undermine, reliability. The eastern LMP-based markets have already seen the benefits of these efficient price signals.

Further, the CAISO will no longer make separate payments to Market Participants to relieve congestion. Under LMP, to the extent suppliers attempt to inject excessive amounts of Energy into the grid in Real-Time, the locational price they would earn would be near zero or negative.[36] Market participants that create congestion in the Day-Ahead market will pay for such congestion because the Day-Ahead market is financially binding. Thus, there will be no physical opportunity or financial incentive for suppliers to engage in the "DEC" game. This should result in fewer Real-Time operational problems as well as lower overall costs to consumers.

#### c. An LMP Congestion Management Scheme Will Discourage Gaming And Market Manipulation

It is indisputable that gaming and market manipulation have been rampant in the California market.[37] Implementing LMP should serve to deter much of this behavior.

In memoranda dated December 6, 2000 and December 8, 2000, attorneys for Enron Corporation detailed various strategies that were being used by Enron and other market participants to game and/or manipulate the energy market in California. As a result of the Enron memos, the CAISO conducted its own studies regarding the extent and impact of gaming and market manipulation in its markets. An October 4, 2002 '*Analysis of Trading and Scheduling Strategies Described in Enron Memos"* ("October 4 Report) provides analysis regarding the ten scheduling and trading strategies outlined in the Enron memos. The

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[36] *See* "*Comments on Mitigating Local Market Power and Interim Measures For Intra-zonal Congestion Management"* filed by the CAISO's Market Surveillance Committee on September 12, 2002 in Docket Nos. ER02-1656, *et al.*

[37] *See,* "Final Report on Price Manipulation in Western Markets", *Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices,* Docket No. PA02-2-000 (March 2003) ("Final Report"). Based on the Final Report, on June 25, 2003, the Commission issued an "Order To Show Cause Concerning Gaming and/or Anomalous Market Behavior in Docket Nos.EL03-180, *et al. American Electric Power Service Corporation, et al.*, 103 FERC ¶61,345 (2003) ("Show Cause Order"). In the Show Cause Order, the Commission determined that over 40 entities "appear to have participated in activities (Gaming Practices) that constitute gaming and/or anomalous market behavior in violation of" the ISO Tariff during the period from January 1, 2000 to June 20, 2001. Show Cause Order at P 1.

October 4 Report suggests that the Enron gaming strategies were prevalent in the California market and were likely employed extensively by entities other than Enron. In addition, the October 4 Report identifies the potential adverse operational and/or reliability effects of such gaming strategies.

Further, in March 2003, the Commission Staff issued its Final Report in Docket No. PA02-2. The Final Report concluded that the CAISO's congestion management scheme caused certain market efficiencies and created opportunities for Enron and other suppliers to develop and engage in gaming and market manipulation strategies designed to take advantage of the market. The Staff found that numerous market participants may have engaged in "games" similar to those employed by Enron. The Staff also found that these market manipulation schemes had profound adverse impacts on market outcomes. Indeed, the Final Report stated that the cumulative effect of gaming in the CAISO markets "is that customers did not pay just and reasonable rates for wholesale electricity." Final Report at VI-35.

Several of the gaming strategies discussed in the Enron memoranda primarily were tailored to take advantage of flaws in the California market design, particularly the CAISO's zonal congestion management system (which was not designed to manage congestion within zones). Many of the strategies depended on the existence of a Day-Ahead or Hour-Ahead schedule for power sales that were developed without determining whether such Day-Ahead or Hour-Ahead schedules were physically feasible. Certain market participants also took advantage of the inconsistent pricing between the forward markets and Real-Time.

Unlike the existing zonal congestion system, the CAISO proposes to utilize a nodal congestion management system and LMP, in conjunction with physically feasible and financially binding Day-Ahead schedules. The use of a nodal congestion management system, in conjunction with LMP and the full network model, will ensure that constraints are considered in developing Day-Ahead schedules, and any congestion is reflected in the prices for energy and transmission services. Thus, all schedules submitted by SCs must be physically feasible, and there is no need for the CAISO to make separate payments in Real-Time to relieve congestion in the Day-Ahead schedule as there is today. Under the CAISO's proposal, Day-Ahead and Hour-Ahead schedules will be financially binding so suppliers that change their schedules in Real-Time still will be financially liable for their Day-Ahead and Hour-Ahead schedules. This reduces the opportunities and incentives for market manipulation strategies that rely on differences between Day-Ahead and Real-Time prices. By enforcing feasible schedules in the forward markets and providing consistent price signals for energy and congestion between the forward and Real-Time Energy markets, the MD02 market design will reduce opportunities for market participants to engage in certain gaming and market manipulation strategies that have occurred under the CAISO's existing market design, *i.e.*, the Enron trading strategies known as

“Non-firm Export, “Scheduling Energy to Collect Congestion Charges” and “Wheel Out”, will be largely eliminated.

#### d. LMP Provides More Accurate Price Signals, And Should Facilitate Improved Generation and Transmission Planning, And Demand Response

LMP is an efficient method of pricing the effects of congestion. LMP prices these effects at each node, thereby allowing market participants to determine, in a fully transparent manner, how prices at their respective locations are impacted by the re-dispatch of generation to relieve transmission constraints. By accurately pricing the effects of congestion, LMP directly and accurately assigns the costs of congestion. In particular, LMP allocates scarce transmission capacity to those who value it the most, and it relies on an “incentive-type” system that encourages market participants to buy and sell power in a manner that is consistent with reliable operation of the transmission grid. Specifically, LMP assigns congestion costs to the transactions that cause congestion. Because Market Participants will see first-hand and be responsible for the financial effects of their decisions on congestion costs, they will have an incentive to manage transactions in a manner that is consistent with least-cost dispatch and with reliable system operations.

LMP should lead to least-cost dispatch and the lowest possible prices while fairly compensating suppliers. The SCUC optimization allows the CAISO to select the most efficient units that are not already committed under long-term contracts for dispatch and produce a set of prices for each time interval and node that is transparent to all market participants. The only alternative to a single price auction is a pay-as-bid method.

LMP will send more accurate price signals that will encourage efficient supply and demand decisions in both the short- and long- run. LMP is expected to promote efficient trading and reflect the opportunity costs of transmission paths. It will further facilitate the efficient use of the transmission system and the development of competitive power markets.

LMP also provides improved price signals and incentives for generation and transmission investment and improved demand response. Without locational prices, the costs of congestion remain hidden. If congestion costs are not known or are inappropriately allocated, suppliers (including demand response) and transmission developers will not have clear signals and financial incentives as to where to locate and identify potential investments. By increasing transparency regarding price differentials between areas, LMP will send better signals to both load and generation on where to locate on the system. Specifically, LMP encourages market participants to locate generation and demand-side capital where LMPs are highest, thereby optimizing total system investment.[38] LMP also will be useful in assessing the benefits (*e.g.*, lower prices) that would result from an expansion/upgrade of transmission facilities. Without the proper price signals, investment in new infrastructure may not be properly located so that it can provide maximum benefits to the system and to consumers. Further, LMP price signals could address market power concerns by encouraging investment in areas of the grid that are generally non-competitive. However, the CAISO does not believe that allowing prices at such locations to rise above competitive levels is necessary or appropriate to attract new investment. Absent true physical scarcity, a price differential reflective of the fact that higher cost units are necessary to serve load in the constrained area is the appropriate price signal for new investment. In the event of true scarcity, *i.e.*, insufficient supply in the constrained area to serve all load within that area, the CAISO proposes to set LMPs based on the marginal Demand bid. In the event that Demand bids are insufficient to clear supply, and self-scheduled (*i.e.*, price-taker) load has to be curtailed, prices will be set administratively at the level of the Damage Control Bid Cap, which will provide scarcity rents to supply resources and provide additional investment incentives.

Finally, as discussed in greater detail in Section III.B.4, LMP will encourage demand response by Participating Loads because such loads will be able to receive the applicable nodal price when they respond to a CAISO dispatch instruction. *See* Attachment F at 5.

### 2. Simultaneous Optimization Of Energy, Congestion Management, Ancillary Services And Unit Commitment In The Forward Markets

As discussed in Section 2.2.2 of the amended Comprehensive Market Design Proposal, the CAISO proposes to operate a forward energy market that eliminates the market separation rule and balanced schedule requirement, and will clear all economic demand and supply bids. The CAISO will simultaneously manage congestion, as well as select the most economical mix of resources to provide needed Energy and Ancillary Services for the next day. The CAISO will use a SCUC optimization routine to minimize the cost of meeting scheduled demand and clearing economic demand bids subject to all transmission and generator performance constraints. The CAISO's proposal is consistent with the security constrained, least cost dispatch approach set forth in the SMD NOPR. *See* SMD NOPR at PP 216-235; *see also* White Paper at 9-10. Further, the CAISO's proposal is consistent with the least cost, security constrained unit commitment and dispatch algorithms used by other independent system

[38] Merchant generation investment is primarily driven by factors such as the availability of long-term contracts and access to fuel supplies and transmission, rather than high locational spot prices, particularly because the investment itself will serve to reduce LMPs. However, LSEs in high-priced constrained areas will have a strong incentive to consider new generation, demand response and/or transmission expansions. LMP also will encourage generators to avoid areas where the grid cannot accommodate the full output of a new resource.

operators such as the New York ISO and the Midwest ISO. *See Midwest Independent Transmission System Operator, Inc.*, 102 FERC ¶ 61,196 (2003); *New York Independent System Operator, Inc.*, 97 FERC ¶ 61,242 (2001).

Under the CAISO's proposal, SCs will submit Preferred Schedules to the IFM that may consist of any of the following:

(1) Supply bids – bids to supply energy or A/S capacity at no less than specified prices. A/S capacity may be provided by qualified supply-side and demand-side resources.

(2) Demand bids – bids to purchase energy at no more than specified prices.

(3) Energy self-schedules – preferred quantities of energy supply or demand submitted without associated energy bids. Submitted self schedules may or may not be balanced (*i.e.*, supply equals demand). Because the market separation rule will be eliminated, even if self-schedules are submitted as balanced, there is no guarantee that they will remain balanced after the running of the IFM.

(4) A/S self-provision nominations – supply-side or demand-side A/S capacity offered for A/S self-provision.

SCs will submit Energy bids on their preferred load and generation schedules that will be used both to clear congestion and clear Energy trades. As a result, balanced schedules for each SC will be an option rather than a requirement. Management of congestion using this market-based approach will be difficult to achieve if SCs' schedules are kept in balance. Accordingly, the CAISO will create economic Energy trades to minimize the total bid cost (*i.e.*, maximize the total societal benefit), thereby eliminating the market separation rule and the distinction between adjustment bids and Energy bids.

The IFM, while respecting self-schedules with no economic bids, will optimize all resources and loads submitted with bids to clear congestion, execute economic Energy trades and procure A/S. This is the economic run of the IFM. Both balanced and unbalanced self-schedules are included in this run in order to balance the supply and demand of the system subject to transmission and generator performance constraints. All self-schedules are treated as price takers in this run, and are adjusted only if necessary to achieve system balance after feasible bids are exhausted. However, once effective economic bids are exhausted, all self-schedules do not have the same scheduling priority. For example, balanced ETC schedules have a higher scheduling priority than other balanced or unbalanced self-schedules. Moreover, the demand-side of preferred balanced self-schedules protected by CRRs have a higher scheduling priority than demand self-schedules not protected by CRRs. If there are insufficient supply bids to cover self-scheduled inelastic loads, then all such loads that are not ETC or CRR-protected will be reduced *pro rata* in the absence of congestion in order to achieve system balance.[39] If load reduction is necessary to relieve congestion, loads will be reduced based on effectiveness, *i.e.*, the reductions will be based on a minimum shift objective, rather than on a *pro rata* basis. This provision prevents unbalanced self-schedules from competing with balanced preferred self-schedules protected by ETCs or CRRs in the event load must be adjusted to clear congestion. If all congestion can be cleared in this economic run, then there will be no need to perform non-economic adjustments on balanced self-schedules.[40]

The objective function of the CAISO's simultaneous optimization of Energy and Ancillary Services is bid cost minimization. This is consistent with the optimization software packages utilized by the other independent system operators. The CAISO rejected an objective function based on total payment minimization. A total payment minimization objective generally could lead to inefficient outcomes for the following reasons: (1) generators would not necessarily be receiving the marginal value of their outputs; consequently, in the short run, this approach could lead to a different bidding strategy targeting higher profit margins for these firms (which could effectively increase rather than reduce the payment by the load serving entities); (2) this pricing mechanism could discourage economic maintenance, upgrading, and other decisions that impact the amount of capacity available to provide energy and A/S; (3) a payment minimization objective can break the important link between pricing of transmission congestion and pricing of energy and A/S, which could make the CAISO's congestion management process more susceptible to the exercise of unilateral market power; and (4) the payment minimization objective in practice is not well understood because it has not been implemented in most of the currently operational markets, and there is no empirical evidence to gauge its impact on bidding behavior and resulting price. The bid-cost optimization algorithm will price Energy and A/S based on the marginal price of meeting the last increment of demand for the relevant product. This is not true for a payment minimization algorithm.

### 3. Supply Resources Should Be Settled On A Nodal Basis

The CAISO proposes to settle with generators based on the applicable nodal price, as determined by the SCUC optimization and, potentially, the proposed local market power mitigation measures discussed below. Settling with supply resources on a nodal basis is a fundamental requirement of congestion management reform because it is crucial to eliminating the troublesome

[39] If there is congestion, the reduction in each category will be based on effectiveness and will not be *pro rata*.

[40] If the CAISO were to maintain the market separation rule in managing congestion on a grid consisting of thousands of nodes, the CAISO would run out of adjustment bids and be forced to make non-economic pro-rata curtailments.

distinction between Inter-zonal and Intra-zonal congestion. Today all supply resources within one of the CAISO's congestion zones are paid for imbalance energy at the zonal price, then paid an additional amount as-bid when re-dispatch is needed to manage intra-zonal congestion. Any additional costs associated with intra-zonal re-dispatch are recovered through an uplift to the zonal market clearing price ("MCP"). In contrast, under the proposed LMP approach, local transmission constraints are managed by modeling the full network in the forward and real-time market optimizations, and supply resources are settled at nodal prices. This makes it unnecessary to have any distinct procedures or uplift charges for local re-dispatch. Thus, although some Market Participants question the use of nodal prices to settle supply resources, the CAISO believes that settlement of supply resources at nodal prices is so fundamental to the MD02 design that it cannot be relinquished without compromising the effectiveness of the entire redesign effort.[41]

The CAISO proposes to permit imports to set marginal clearing prices under Phases II and III; however, imports would be subject to AMP. In order for nodal pricing to function properly and for "true" prices to be established at each node, it is necessary that imports be permitted to set the clearing prices at a node. In that regard, not allowing imports to set the price would be problematic because congestion prices in the forward market for external paths are determined based on energy price differentials across the inter-tie. If inter-tie bids cannot set the MCP, there will be no price differential during congested periods and, therefore, no congestion price. Thus, inter-tie bids need to be eligible to set the clearing price in order to establish congestion prices at the interties.

Also, it is both prudent and appropriate to apply AMP to imports if imports are permitted to set clearing prices. Applying AMP to imports will be even more important when the CAISO eventually implements a looped network because an external looped network will mean that the price at one intertie could have an impact on prices at other nodes.

The CAISO recognizes that the decision whether to apply AMP to imports must assess the need to provide some measure of protection against the exercise of market power and gaming, while not discouraging import participation in CAISO markets. The CAISO believes that this balance is appropriately struck by permitting imports to set clearing prices, but subjecting them to AMP. Applying AMP to imports is necessary otherwise market participants owning generation internal to the CAISO Control Area would have an opportunity to engage in "megawatt laundering".[42] Specifically, if imports are allowed to set the

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41 The CAISO notes that the eastern independent system operators that employ LMP settle generation at the nodal level, and the White Paper contemplates that generation will be settled at the nodal level. White Paper, Appendix A at 10.

42 The Commission has recognized on several occasions that there are significant concerns about "mega-watt laundering" in California. *San Diego Gas and Electric Company v. Sellers of*

clearing price but are not subject to AMP, internal generators would have a strong incentive to circumvent AMP mitigation by "megawatt laundering" some of their capacity to unmitigated parties in order to avoid AMP and set a high price through a submitted import bid to the benefit of their entire portfolio. The CAISO does not believe that the application of AMP to imports will exacerbate "seams" issues or dampen import participation in CAISO markets. Although the application of AMP to imports by itself could serve to deter import participation in CAISO markets, that should be offset by the opportunity for imports to set market clearing prices — an opportunity they do not currently have. Imports would have more certainty regarding the prices they would be paid for energy than they do under the existing pricing regime in which they are price takers. This increased certainty should promote increased participation by imports in CAISO markets even though the possibility exists that import bids could be mitigated under AMP. In any event, if market power is to be effectively mitigated, it must be applied to all market participants. By applying AMP to imports – which are an integral component of the California market – the CAISO is merely according equal treatment to all sellers of electricity in California.[43]

Finally, the CAISO submits that, settling with generators at a nodal price, requires that effective local market power mitigation measures be in place so that suppliers cannot exert market power and set unreasonably high nodal prices in those areas of the grid that are transmission constrained and where competitive alternatives are lacking.

#### 4. Load Aggregation

In its May 1 Filing, the CAISO proposed to schedule and settle loads at the Demand Zone level and, when technically feasible, at the Load Group level. The May 1 Filing contemplated approximately 20 Demand Zones in the CAISO Control Area and over 40 Load Groups. Numerous parties expressed anxiety that LMP pricing will have a significant negative cost impact on them. The issue of whether the LMP default settlement for loads should be an aggregation was also raised in the LMP Working Group. Numerous market participants stated their concern that settling load on a nodal basis could have a significant and immediate adverse cost impact on them.[44]

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*Energy and Ancillary Services into Market Operated by the California Independent System Operator and the California Power* Exchange, 95 FERC ¶61,418 at 62,564, *order on* reh'g, 97 FERC ¶61,275 (2000).

[43] Applying AMP to imports provides for a more equitable and comprehensive mitigation approach.

[44] The potential for severe cost impacts on consumers in congested areas results from constraints in a transmission system that was designed and constructed under an entirely different regulatory and commercial regime.

The CAISO has consistently recognized the legitimate equity issues raised by these parties. In that regard, the potential for severe cost impacts on consumers in congested areas results from constraints in a transmission system that was designed and constructed under an entirely different regulatory regime — a regime that did not anticipate competitive generation markets and nodal pricing. Accordingly, the CAISO proposes to modify its initial proposal to better accommodate such concerns. Specifically, the CAISO proposes to establish three mandatory default load aggregation pricing areas for load scheduling, bidding and settlement: the PG & E transmission service territory; the SCE transmission service territory; and SDG & E transmission service territory.[45] LSEs within these boundaries – including municipal utilities and non-utility retail service providers – would be required to schedule loads at this level, and the CAISO would settle loads based on aggregate prices that are the averages of the nodal prices in the respective service territory.[46]

The approach proposed by the CAISO is consistent with the methodology employed by PJM, the NYISO, and ISO New England, all of which settle loads at a high level of aggregation.[47] Further, the Commission's recently issued White Paper contemplates that an independent system operator may use zonal or nodal prices for buyers of electricity. White Paper, Appendix A at 10. The CAISO's proposal should effectively address the concerns of parties regarding LMP cost impacts on loads without sacrificing the primary benefits of LMP for the California market. In particular, the CAISO's load aggregation proposal would insulate consumers from potentially high nodal prices in constrained areas of the transmission grid.

Because the nodal prices produced by the IFM can exceed the $250/MWh Damage Control Bid Cap in the presence of congestion and inelastic load, the CAISO will cap the nodal prices used for settlement of aggregated loads at the level of the Damage Control Bid Cap, *i.e.*, $250/MWh initially. If this results in a revenue shortfall because total payments to generators (and, to the extent applicable, to CRR holders) exceed total receipts from loads (and, to the extent applicable, from counter-flow revenues) in any settlement period,[48] the CAISO will recover the difference through an uplift. This proposal addresses the

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45 *See* Sections 2.2.2 and 2.6 of the amended Comprehensive Market Design Proposal.

46 Although the CAISO will settle loads on an aggregated basis, the CAISO will publish nodal prices.

47 For example, PJM settles loads at the Utility Distribution Company level. ISO New England has eight load zones (three in Massachusetts and one in each of the other states), and the load in each zone pays the zonal price which is the load-weighted average of the nodal prices in that zone. *See, e.g., ISO New England, Inc.*, 91 FERC ¶ 61,131at 62,069-71 (2000).

48 This mismatch can occur because the CAISO will settle with suppliers on a nodal basis but will settle with load on an aggregated basis.

concerns of market participants that prices could well exceed $250/MWh in a LMP pricing regime and will make LMP more palatable to consumers and policy makers in California. As the Commission is well aware, there has been significant opposition to LMP in California due to a concern that nodal pricing will cause significant price increases. The CAISO's proposal should allay such fears because it limits nodal prices to the level of the current Damage Control Bid Cap, *i.e.*, $250/MWh.[49] In addition, the proposal is reasonable because it ensures that supplies that bid below $250/MWh will not be paid higher prices due to inelastic demand and/or binding transmission constraints.

A related issue raised in the LMP Working Group was whether loads would have an option to "opt-out" of the aggregation. Many parties argued that the opt-out capability should be removed, at least initially, until the market has gained some experience with nodal prices and can estimate the effect on the aggregate prices of loads at low-price nodes opting-out. The CAISO proposes to make load aggregation mandatory so that loads will not have the option to "opt-out" of the aggregation. The CAISO believes that this approach is appropriate because it will preclude loads at low-priced nodes from opting-out and thereby raising the prices at the remaining nodes. This should allow Market Participants to become comfortable with LMP and mitigate any concerns about the potential adverse impacts of nodal pricing. The CAISO's proposal also will result in a simpler initial implementation for both scheduling and settlements, as well as a simpler initial CRR allocation.

Even though the CAISO will not be settling all load on a nodal basis, the CAISO's proposal will still preserve the major benefits of LMP for the CAISO markets. In particular, by allocating aggregated load schedules and bids to the individual nodes based on accurate load distribution factors, the CAISO will perform congestion management at the nodal level based on a realistic distribution of load across the grid and will produce a complete set of nodal prices for each settlement period. This will provide accurate pricing information that reflects the impacts of transmission constraints (to serve as guidance for potential investors and policy makers regarding the preferred location(s) of new generation and transmission facilities).

In addition, the CAISO's proposal will still accommodate and facilitate demand response. In that regard, load that participates in the CAISO's Participating Load Program and responds to a CAISO Real-Time dispatch instruction will be treated the same as generation and settled at the applicable nodal price. Any uninstructed energy from such Participating Load would be settled at the applicable "aggregated" price. This proposal will allow "responsive" load to settle at the nodal price without extending the benefit to "normal" load. In other words, only the amount of load that needs to be dispatched in Real-Time to relieve specific constraints will settle at the nodal price. The MSC has

[49] Generators that bid above $250/MWh are eligible to be paid "as-bid" under the soft cap provided they cost-justify their bids.

recognized that this should result in improved demand responsiveness. Attachment F at 5.

### 5. Testing of LMP

In the LMP Working Group, several parties expressed concern that the LMP model could result in significant price increases and volatility and significant cost impacts on loads located in constrained areas of the grid. They requested that adequate time be set aside for testing and market simulation. Parties also argued that without real price impacts, they will be unable to assess the actual impacts of LMP implementation. Accordingly, the LMP Working Group considered whether there should be a transition period for testing and implementation of LMP.

The CAISO notes that it has established a Program Management Office ("PMO") to oversee MD02 implementation. The PMO has attempted to develop "best practices" procedures to govern implementation of the Phases II and III elements of the comprehensive, integrated MD02 proposal. This "best practices" process follows a prudent Systems Development Life Cycle. There are four steps for implementation of MD02 – Initiation, Elaboration, Construction and Implementation.

The PMO has developed a Phase III project plan that attempts to minimize risk both to the CAISO and to Market Participants, yet respects the Commission's and the CAISO's desire to remedy the underlying flaws in the CAISO's market design as soon as possible.

Under the PMO approach, extensive testing is included in the Construction stage. The testing phase includes unit, systems, integration, end-to-end, load and performance and user acceptance testing, as well as market simulation. Implementation of LMP and the full network model will require extensive software and systems development. The CAISO will need to undertake extensive and 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 CAISO estimates that several months of systems, software and market testing (including publication of the LMPs that might be created under test conditions) will be necessary for Phase III. Sufficient market testing and LMP simulation should allow all Market Participants to become familiar with the results that a LMP scheme will produce.[50] Throughout the implementation process, the CAISO has been and will continue providing Market Participants with empirical pricing analyses. On

[50] The CAISO will utilize a network model developed on its EMS system that incorporates detailed representations of PG&E's, SCE's and SDG&E's transmission systems. Using that model, the CAISO will perform the State Estimator solution. The CAISO will test the EMS State Estimator solution and produce LMPs that represent actual operational conditions.

September 30, 2002, the CAISO completed its initial LMP Price Dispersion Study and provided the results of such study to stakeholders. That study was based on historical data from March, July and August 1999. [51] On February 4, 2003, the CAISO completed its second LMP Price Dispersion Study titled "*Analysis of Cost-Based Price Differentials Across Nodes*". This study, which was based on market data for the full year of 1999, combined with current network data and resource data (including new generation), also was provided to stakeholders for their review. The primary purpose of these studies was to illustrate the potential variation of LMPs across nodes on the CAISO Controlled Grid.

The CAISO is currently conducting another LMP Simulation Study using current market bids (as well as current network data) and an AC OPF model to derive illustrative market outcomes assuming the MD02 market design was in place today.[52] This LMP study will report the results for a full year of simulation. The CAISO recognizes that, until the actual MD02 market software is created and ready for testing, the CAISO can only simulate actual LMP outcomes, based on reasonable but not necessarily accurate assumptions. Such simulations can be illustrative of LMP outcomes, but cannot and should not be viewed as accurate forecasts of the results LMP will produce once the new market design is in actual operation. It is impossible to predict accurately how participants' bidding behavior will change once the new systems are used for scheduling and settlement. The CAISO therefore cautions against placing too much emphasis on the empirical LMP study results that are derived using existing market data that make assumptions about future market behavior.[53]

The Phase III modifications represent a complete paradigm shift in design of the CAISO's markets. It will necessarily take the CAISO and market participants time to correct problems with and acclimate to the new market design. Given the scope and complexity of the changes, adequate testing by

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[51] The CAISO stressed that the results of the Initial Study could not be viewed as expected or predicted LMPs. Rather, the simulations merely illustrated potential patterns of LMP variations across nodes.

[52] Of course, it must be recognized that such market bids are being submitted in a zonal market not a nodal market as will be in effect under MD02.

[53] One question that was raised in the LMP Working Group regarding the cost impact of LMP was whether the price variation that occurs under the LMP model could somehow result in higher average costs to consumers. The CAISO believes that, all things being equal, this will not occur. In fact, LMP should result in lower overall costs because the forward and Real-Time optimization will commit and dispatch resources more efficiently than the current markets do. In addition, under LMP, accurate pricing of congestion impacts and the settlement of supply resources at nodal prices will provide better incentives for resources to follow schedules and CAISO dispatch instructions. As noted in an earlier section, as long as the CAISO has effective measures to mitigate local market power, the prices produced by LMP will represent the most efficient use of supply resources and the transmission grid, even though those prices will reveal much more variation than is visible in today's zonal prices.

both the CAISO and market participants is necessary. The CAISO submits that its timeline for testing is reasonable given the extensive scope and complexity of the changes.

The CAISO should not be required to rush to implement a new market design without the proper testing and analysis. The CAISO seeks to avoid the mistakes of the past and the problems that likely would follow from a hurried implementation of LMP. The CAISO notes that it took the NYISO approximately two years to implement nodal pricing. The CAISO is developing an implementation timetable that provides for sufficient testing and cannot be viewed as unreasonable, especially given the extent of prior market design related problems in California following the break-neck implementation timetable leading to CAISO start-up. [54]

On the other hand, there is no reason to wait several years to implement LMP. LMP has been implemented successfully in other regions and there is no reason LMP cannot be implemented successfully in California.[55] Given that the current market design has several recognized flaws, it is imperative that the new market design be implemented without unnecessary delay.

The MSC has recognized the concerns of market participants regarding the need for extensive testing of LMP. Although the MSC acknowledges their concerns, the MSC has concluded that the CAISO is properly addressing such issues. Specifically, the MSC has stated:

> We also feel that the ISO's most recent plan for testing and implementing its MD02 design, for the most part, satisfies the concerns that have been raised. The application of LMP to retail loads has

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[54] The CRR Subgroup of the LMP Working Group raised the issue whether the CAISO should evaluate the results of the CRR allocation prior to moving forward with LMP implementation. Certain parties argued that the CAISO should not move forward with LMP implementation until a CRR allocation has consensus support from all LSEs. The CAISO is currently conducting CRR studies designed to evaluate the availability. As indicated above, the CAISO proposes to extensively test and evaluate the new market design. If there are flaws, the CAISO will not implement such new market design until the flaws are corrected. However, objections that individual parties may have to LMP and/or CRR allocation should not serve as the basis for delaying LMP implementation absent design flaws.

[55] On March 7, 2003, ISO New England issued a report on the first hundred hours of operation under its new standard market design that includes LMP and a multi-settlement system for the energy market. *See Standard Market Design Implementation Report, March 1-March 4* (March 7, 2003). The report states that the implementation of standard market design has "proceeded smoothly" and "electricity prices experienced in New England have been consistent with the cost of fuel and other wholesale electric markets in the Northeast." There is no reason to think that California's implementation of LMP will proceed any less smoothly, especially given all of the testing and studies that the CAISO will undertake.

> been indefinitely postponed, and participants will therefore have ample time to observe the actual prices resulting market operations before any decisions about application of those prices to retail loads are taken. The current schedule for implementation of MD02 is by no means hasty and already calls for extensive *testing* during parallel operations with existing systems, as opposed to simulation using predictions about prospective market conditions.

Attachment F at 1.

The MSC appropriately recognizes that the CAISO has modified its proposed scheduling and settlement of Loads to require settlement at an aggregated level. Further, the MSC states that "the current ISO proposal would allow for the ISO and participants to observe the resulting implied prices for a considerable time before any decisions are made about whether or how to apply them to retail loads." Attachment F at 3.

### 6. AC OPF, SCUC and Marginal Losses

The CAISO proposes that Real-Time dispatch be based on the results of Security Constrained Economic Dispatch ("SCED") which uses an power flow model. SCED will minimize the Real-Time cost of Imbalance Energy, determined from Energy bids submitted by participating resources, subject to transmission, nomogram, and resource capability constraints, while accounting for transmission losses. The CAISO proposes that the integrated forward market will be optimized based on the results of an AC power flow-based SCUC ("AC-SCUC") that will minimize the bid cost of energy and A/S, subject to transmission, nomogram and resource capability constraints, while accounting for transmission losses. Thus, the CAISO will incorporate the cost of losses into the locational marginal prices produced by the IFM optimization.[56] Each nodal LMP is decomposed into three components, a reference energy price (*i.e.*, system energy absent transmission constraints and losses), a marginal loss adder and a congestion adder.

Power flow models function as either a DC model or an AC model. The DC models are widely used and are generally easier to operate. They are also more robust and can provide repeatable solutions. However, the DC models do not incorporate accurate calculations of losses and do not model factors such as voltage constraints and reactive power limits.

[56] *See* Section 2.2.12 of the amended Comprehensive Market Design Proposal.

Although an AC model is more complex than a DC model, it has numerous benefits that outweigh the complexity. AC models can incorporate features of the transmission system such as voltage constraints and reactive power limits that are not accommodated in DC models. An AC model also calculates losses on a marginal loss rate, which provides a more accurate representation of a transaction's impact on the network. The loss characteristics of the AC model increase the accuracy of dispatch of resources by calculating the effects of losses on congestion in the network. For these reasons, the CAISO proposes to utilize an AC power flow model.

As noted above, an AC model calculates losses based on a marginal loss rate. If losses were to be assessed and charged on that basis, revenues would exceed loss costs. That is why the CAISO currently uses a scaled marginal loss methodology. Going-forward, the cost of transmission losses can be recovered using either marginal losses or average losses. Because the CAISO recommends utilization of an AC power flow model, the CAISO proposes to calculate losses using a marginal loss rate. This is consistent with the approach utilized by the New York ISO (and the approach that PJM is proposing to utilize in the future). The collection using marginal losses (through LMP) is larger than using average losses, typically about twice as much. Marginal losses are necessary to achieve least cost unit dispatch and are advantageous in simplifying generator bids because generators do not have to guess the losses.[57] Using marginal losses will promote a more efficient use of the transmission system because marginal losses are included in the congestion solution rather than simply "tacked on" after the fact. Pricing losses on a marginal basis is important to establishing nodal prices that accurately reflect the cost of supplying additional load at each node.

Charging marginal losses will result in the collection of surplus revenues that must be returned to transmission customers. The CAISO proposes to add such over-collection of losses to the CRR Balancing Account. During the stakeholder process, CAISO Market Participants were generally supportive of allocating these excess revenues to the CRR Balancing Account. The benefits of CAISO's proposal are:

(1) It would make CRRs more valuable because it would increase the possibility that CRR holders would receive a full hedge. Market Participants indicated that this is very important to them;

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[57] In a large geographic area, losses can be significant, and pricing them on a marginal basis is important to establishing nodal prices that accurately reflect the cost of supplying additional load at each node. An average loss mechanism usually results in prices that produce a higher cost dispatch, entail cross subsidization and add to uplift charges. Although an average loss mechanism may be acceptable if losses are small, or as a transition mechanism, the use of marginal losses is generally preferable.

(2) The proposed approach is easier to implement than other options because the CAISO would not have to keep track locations where loss revenues are over-collected; and

(3) If there are surplus funds in the CRR Balancing Account (after CRR holders are paid their entitlement at the time of the yearly clearing), such funds will be paid to Participating Transmission Owners to reduce their transmission Access Charge.

The CAISO acknowledges that, if it were to charge average losses, it would not need to create a mechanism to return surplus funds. Although such an approach has the benefit of simplicity, the CAISO submits that an approach that promotes greater efficiency, *i.e.*, using marginal losses, is preferable. Indeed, the Commission, in recently approving the use of marginal losses by the Midwest Independent Transmission System Operator ("MISO"), found that marginal losses are required to assure least cost dispatch. *Midwest Independent Transmission System Operator, Inc.*, 102 FERC ¶ 61,196 at P 53 (2003). The Commission noted that an average loss mechanism results in prices that produce a higher cost dispatch and entail cross subsidies. *Id.* Finally use of marginal losses is consistent with the CAISO's proposed use of energy prices and transmission usage charges that are based on marginal costs.

### 7. The Full Network Model

As discussed in greater detail in Section 2.2.4 of the amended comprehensive Market Design proposal, the CAISO is proposing a forward congestion management procedure that adjusts generation and load (and import and export schedules) to clear congestion using a SCUC tool with an embedded AC power flow to enforce linear transmission constraints using a full network model ("FNM"). That FNM includes buses and accurately represents transmission constraints and interfaces of the CAISO Control Area and incorporates a model of the Western Electricity Coordinating Council ("WECC") regional grid external to the CAISO Control Area. The external model will ultimately be a "closed loop" model that represents external electric connections between the various interties into the CAISO Control Area. This will allow the CAISO to estimate and manage parallel path or "loop" flows in coordination with other control areas in the region. In particular, the "closed-loop" FNM will accurately model loop flows due to internal resources and will result in accurate scheduling and dispatch of these resources to address congestion within the CAISO-controlled grid.

The FNM proposal offers a number of desirable features. First, it is consistent with a point-to-point approach to scheduling and congestion management. In contrast, the contract path paradigm which, even though it has long been standard industry practice, is inconsistent with the physics of power flows. Second, the FNM proposal provides a practical basis for western regional coordination of congestion management, as is currently being discussed by the

Seams Steering Group-Western Interconnection ("SSG-WI") Congestion Management Alignment Working Group ("CMAWG"). Within the CMAWG, the CAISO is exploring with other regional participants how best to coordinate congestion management at the seams using a reduced model of the WECC regional network that realistically captures inter-regional flows, yet provides the individual regional transmission system operators the flexibility to perform grid allocation and congestion management in ways that best meet the needs of their market participants. The CAISO's intent is that the FNM ultimately implemented by the CAISO will be fully consistent with the outcome of the CMAWG efforts. Finally, a reduced external closed-loop model makes forward congestion management more realistic than the current approach of treating the interties into the CAISO control area like separate quills on a porcupine. Specifically, the closed-loop model will recognize and quantify that portion of a forward energy schedule at any given intertie point that will flow through the external network to ultimately enter California. Such unscheduled flows in the West and internal to the CAISO have heretofore been managed exclusively through Real-Time re-dispatch to prevent or relieve line overloads.[58]

Implementation of the FNM, which incorporates a closed-loop approach, is dependent on the availability and use of modeling data throughout the Western Interconnection. Although the CAISO believes that use of a closed-loop is the proper way to model the grid and perform congestion management, the CAISO recognizes that it may be problematic to implement this approach prior to development of a coordinated congestion management procedure for the entire West. Accordingly, the CAISO is evaluating how to model the system in the most effective and efficient manner when it implements LMP initially. It might be necessary for the CAISO to utilize a simpler "open loop" representation of the external network until such time as there is an effective coordinated Western regional framework for Day-Ahead scheduling and congestion management, including explicit scheduling of inter-control area parallel path flows.

In any event, the CAISO is committed to development of a coordinated regional approach to congestion management under which forward schedules are accurately assessed for their flows over all significant inter-RTO paths. The CAISO is actively engaged in developing such an approach through the SSG-WI CMAWG effort and will continue to discuss these issues with CAISO stakeholders and inter-regional market participants. The CAISO commits to reporting back to the Commission at a later date regarding how it will model the external network when it implements LMP. The CAISO will also continue to update the Commission on these efforts through SSG-WI's periodic updates to the Commission.

[58] As the Commission is aware, the West currently manages Real-Time loop flow through the Commission-approved WECC Unscheduled Flow ("USF")procedure.

### 8. Treatment of Constrained Output ("Lumpy") Generators

Constrained-Output Resources are "block-loaded" or "inflexible" generating resources, such as some Combustion Turbines, that must operate at discrete output levels, or cannot easily change load levels. As such, these units, when on-line, are typically restricted to generating at a specific operating point (usually their full capacity for their unit-specific Minimum Run Time). When scheduling these resources in the forward market, the CAISO may have to keep the schedule of a flexible generating resource below the level that it would otherwise have been scheduled, in order to accommodate the inflexible output of such constrained-output resources. When dispatching these resources in Real-Time, the CAISO may have to reduce the Dispatch of another generating resource (possibly below its Hour-Ahead schedule) in order to accommodate the inflexible output of such constrained-output resources.

In the SMD NOPR, the Commission raises the issue whether these so-called "lumpy" generators should be permitted to set the energy price in the Day-Ahead market. SMD NOPR at PP 317-19. Although the Commission appropriately recognizes that allowing "lumpy" generators to set the energy price may have a more direct benefit in the Real-Time market, the Commission expresses some concern about potential negative ramifications of establishing different pricing rules for the Day-Ahead and Real-Time markets. *Id.* at P 319. The CAISO agrees with the Commission's statements in the SMD NOPR that permitting "lumpy" generators to set Real-Time prices under the circumstances identified therein promotes efficient results, and the CAISO's Amendment No. 54 proposes to permit "lumpy" generators to set the price in Real-Time.[59]

With respect to the Day-Ahead market, "lumpy" generators will not set the energy price under MD02. The CAISO does not believe that "lumpy" generators should set the energy price in the forward market just for the sake of having consistent pricing rules in the Day-Ahead and Real-Time markets. In that regard, it is not essential that "lumpy generators" set the energy price in the Day-Ahead market because load can respond to prices in the forward markets, but load has a limited or no ability to respond to prices in Real-Time. The CAISO believes that the limited number of "lumpy" generating facilities will keep the Day-Ahead market sufficiently competitive even when price increments are greater than 1 MW. Pricing efficiencies are less likely to occur by permitting "lumpy"

[59] In the CAISO's July 8, 2003 Amendment No. 54 (*i.e.*, MD02 Phase 1B) filing in Docket No. ER03-1046, the CAISO has proposed that Constrained-Output Resources, which are "block-loaded" or "inflexible" generating resources (*e.g.*, some Combustion Turbines) can set the Real-Time market clearing price when all or a portion of their output is required by the CAISO. When these resources are operating due to constraints but their output is not needed, these resources would not set the price but would be paid their as-bid costs. *See* Amendment No. 54 Transmittal Letter at pages 28-29. The resource that is DEC-ed in Real-Time below its Final Hour-Ahead Schedule to accommodate a lumpy generator will be paid an uplift to compensate it for the charge it incurs for the DEC instruction, to the extent the MCP is above its DEC bid price.

generators to set the price in the Day-Ahead market. Day-Ahead schedules are based only on bids and self-schedules submitted to the CAISO, so Day-Ahead prices cannot result in any unexpected changes in the Day-Ahead schedule. Further, because transmission shadow prices are always set by flexible resources (unless the CAISO runs out of economic bids), a significant drawback of allowing "lumpy" generators to set the Day-Ahead price is that, by enforcing the "lumpy" generator constraint (in order to make the Day-Ahead schedule feasible) the natural relationship between the Day-Ahead Energy and transmission pricing breaks down. This is not a problem in Real-Time because transmission is not explicitly priced or settled in Real-Time. Stated differently, it does not make sense to permit a "lumpy" generator to set the price in the Day-Ahead market because that would essentially involve acceptance of a schedule that is not feasible, knowing that such schedule would have to be adjusted in Real-Time. In other words, the CAISO would be pretending that the Day-Ahead market is purely financial, and that is not the case under either SMD or MD02.

### B. Local Market Power Mitigation Measures

If the CAISO implements LMP, it is imperative that the CAISO have effective LMPM in place. Otherwise, suppliers that are located in transmission-constrained areas will be in a position to exercise locational market power and artificially inflate nodal prices due to the lack of competitive alternatives. Effective local market power mitigation is an essential element of LMP pricing. Stated differently, LMP will not produce just and reasonable rates unless adequate local market power mitigation measures are in place.

The CAISO's existing protections against locational market power are wholly inadequate, inconsistent with the protections which the Commission has approved for other markets and could result in unjust and unreasonable prices in a nodal market. Indeed, the CAISO's MSC, in its *Opinion on the Necessity of Effective Local Market Power Mitigation for a Workably Competitive Wholesale Market* ("LMPM Opinion") issued on May 29, 2003, stated that "[t]he most glaring weakness in the currently operating…[CAISO] market design is the lack of an effective local market power mitigation [LMPM] mechanism." Attachment D at 1.The MSC concluded that

> [if] the MD02 process is to be successful, the CAISO must obtain the authority from the Federal Energy Regulatory Commission to implement an effective LMPM mechanism. Although this sort of LMPM mechanism will not guarantee the success of the MD02 process, it is an important part of the package.

*Id.* Thus, the MSC strongly advocates the need for more effective LMPM measures upon implementation of MD02. The CAISO also views approval of more effective LMPM measures as a necessary adjunct to implementation of LMP.

Further, Commission approval of LMPM measures that are more effective than the LMPM measures currently in effect would provide consumers and State policy makers with increased confidence that California markets will not be subject to rampant market manipulation immediately upon implementation of a new market design. This is extremely important because the CAISO is proposing a comprehensive overhaul of its existing market design, including certain pricing and market design elements that are controversial and being received with skepticism. As the Commission is well aware, there is significant trepidation in California regarding a move to LMP. Effective LMPM measures could help allay stakeholder and State policy maker fears that the new market design might be susceptible to manipulation and the exercise of market power. Indeed, many California parties, including State policy makers, consider Commission approval of more effective LMPM measures to be an essential condition for the CAISO to move forward with implementation of LMP. Thus, effective LMPM measures would go a long way toward facilitating a smooth transition to and implementation of LMP.

Finally, the CAISO notes that in its July 17 Order, the Commission found the PJM-like LMPM measures proposed by the CAISO in its May 1 MD02 Filing to be "inappropriate in light of a three-zone congestion management model". July 17 Order at P 90. Instead, the Commission approved the use of AMP procedures to mitigate the exercise of local market power, finding that "there is a need for an appropriate *interim* measure in order to provide protection from the possible exercise of local market power during the transition to the full network model." *Id.* (emphasis added). Now, that the CAISO is moving to a nodal model, it is appropriate that the Commission approve more effective *permanent* LMPM measures similar to those in place in PJM.

### 1. There Is A Need For Effective Local Market Power Mitigation Measures In Conjunction With LMP

Within the CAISO Control Area, as on any transmission system, locational market power arises because of local transmission constraints, which generally occur along transmission paths entering areas of dense population and, hence, high load.[60] These constraints require the services of specific generation

[60] The problems presented by the potential exercise of locational market power were aptly described in a study by the Department of Energy:

> Electricity markets are dynamic and can change dramatically over the course of just a few hours, creating opportunities to exercise market power even though the market may be very competitive under most circumstances. For example, the geographic scope of the electricity market is determined by the transmission system. Any change in available transmission capacity can quickly alter the geographic boundaries of the market. To cite another example, certain plants may be required to run at certain times in order to meet reliability needs, effectively giving them market power during those periods, because no other plants can act as substitutes.

resources to ensure the reliability of the grid in these areas, and in practically all such situations there is not a workably competitive market to provide such services because local generation is concentrated among one or two suppliers. As a result, the owners of resources that are needed to ensure local reliability are in a position to exercise locational market power. Mitigation is therefore essential under these circumstances.

The Commission has expressly found that there are locations in California where suppliers have locational market power because other generation cannot provide service in the Load pocket. *AES Southland, Inc. and Williams Energy Marketing and Trading Company*, 94 FERC ¶ 61,248 at 61,871-72 (2001). Owners of Generation in such Load pockets (where there is limited transmission capacity to the main grid) are able to demand unreasonable prices for additional Generation needed by the CAISO to ensure local reliability. In his Affidavit submitted with the May 1 Filing, Dr. Eric Hildebrandt discussed how suppliers have exercised local market power successfully so that they can be called out-of-sequence by the CAISO in real time and be paid bid prices for incremental Energy significantly in excess of the real time MCP and their marginal costs of generation. In particular, Dr. Hildebrandt stated that on numerous occasions, Generators have played the incremental Energy bid game ("INC game") and bid capacity at a very high price in the Real-Time market thereby forcing the CAISO to meet local reliability requirements by Dispatching Generation out-of-sequence at high, non-competitive prices. Dr. Hildebrandt's Affidavit included several examples of suppliers engaging in the "INC" game.[61]

Thus, there is clear, incontrovertible evidence that generating unit operators actively seek to exploit locational market power in California when they are in a position to do so. Additional difficulties with regard to locational market power arise in the case of a LMP congestion management scheme. Under the pricing scheme that exists today, when the CAISO dispatches a unit out-of-sequence in order to manage Intra-zonal congestion, the CAISO pays the unit its "as bid" price, but the unit does not set the MCP. However, under LMP, such unit would set the MCP for all supply resources at the applicable node and potentially

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"Horizontal Market Power in Restructured Electricity Markets", Office of Economic, Electricity and Natural Gas Analysis, U.S. Department of Energy, March 2000 at 2. Further, the Commission Staff has recognized the locational market power issue, and stated that "it is important to note that the presence of transmission constraints can redefine the market so as to affect both concentration and market share." Staff's Recommendation on Prospective Market Monitoring and Mitigation for the California Wholesale Electric Power Market dated March 9, 2001 at 11.

[61] In addition, Dr. Hildebrandt submitted an Affidavit in Docket No. ER03-683-000 in support of Amendment No. 50 to the CAISO Tariff, wherein the CAISO proposed more effective measures to mitigate the exercise of local market power during the interim period prior to implementation of LMP. Dr. Hildebrandt's Affidavit described the problem of locational market power within the CAISO system and identifies additional examples of local market power being exercised by suppliers.

could have pricing impacts on surrounding nodes as well, which would make the overall cost impact of local market power much more significant under LMP.

The MSC also has identified the problems associated with local market power in a LMP pricing and congestion management regime. In that regard, in the LMPM Opinion, the MSC stated that

> [t]he primary consequence of these situations is that absent mitigation units with local market power will be able to extract substantial, practically unlimited, profits from the market for the output of those units. A secondary, somewhat less obvious consequence lies in the impact of this local market power on the broader market. Knowing that there is a chance that a portion of a unit's output must be taken, the owner will bid the output less aggressively into the market than it otherwise would. Other firms, knowing that their competitors are likely to compete less aggressively, will also find it profitable to bid less aggressively. This creates a process of negative feedback that can lead to higher prices throughout the entire region. Many of the difficulties encountered in dealing with the local market power problem arise because of this interface between regulated and market-based services.

Attachment D at 2.[62]

For the foregoing reasons, if the CAISO implements LMP, the CAISO must have effective LMPM measures in place to prevent suppliers located in transmission-constrained areas from exercising local market power and artificially raising nodal prices. The MSC agrees that the Commission must allow the CAISO to "implement an effective local market power mitigation mechanism." Attachment D at 11.

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[62] The MSC, in its "Comments on Mitigating Local Market Power and Interim Measures for Intra-Zonal Congestion Management" filed with the Commission on September 12, 2002 in Docket Nos. ER02-1656, *et al.* ("MSC Opinion"), described the local market power problems that would exist in an LMP scheme. Specifically, the MSC noted that:

> [u]nder a locational marginal pricing scheme, local market power is exercised by withholding electricity from the market. This withholding will occur when a generation owner knows a certain amount of electricity must be supplied by some of the units it owns or local demand will not be met because of transmission constraints into this area. Unless there is significant price responsive demand at this location, there is no limit to the price that this unit owner can bid for the required amount of energy. Consequently, without the authority to mitigate the bids of this unit owner when it possesses local market power, there is no limit to price of energy at that location. For this reason, all of the US ISOs that use locational marginal pricing have mechanisms to mitigate the bids of generation unit owners with local market power.

MSC Opinion at 2.

The CAISO notes that RMR contracts mitigate the ability of certain units to exercise locational market power when they are needed for incremental generation. However, RMR contracts do not provide complete protection from the exercise of market power. There are certain events such as temporary transmission outages, unit outages (including outages of RMR Units), and other extraordinary system conditions that can create a need for the CAISO to call virtually any unit on the grid, not just RMR Units, to ensure local system reliability.

### 2. The CAISO's Existing Local Market Power Mitigation Measures Are Wholly Inadequate And Will Result In Unjust And Unreasonable Rates When The CAISO Implements LMP

Under the CAISO's existing local market power mitigation measures, a bid taken out of merit order is deemed to have failed the AMP conduct test. If the out-of-merit bid is more than 200 percent or $50/MWh greater than the MCP, whichever is lower, the bid will be mitigated and the generator will be paid the higher of its reference price or the MCP.

Both the CAISO and the MSC strongly believe that the CAISO's existing local market power mitigation measures are wholly inadequate to protect consumers against the exercise of local market power in a LMP world. Such local market power mitigation measures are flawed in several respects and will result in unjust and unreasonable rates if the CAISO implements LMP. Accordingly, the Commission must approve the PJM-like, local market power mitigation measures proposed by the CAISO in this filing. If the Commission still believes that it is appropriate to apply AMP to mitigate the exercise of local market power in California, then the Commission must approve significantly stricter thresholds than those currently in effect. In Section III.B.4 *infra*, the CAISO offers a less preferred LMPM alternative methodology using AMP and tighter conduct and market impact thresholds than exist today.

The existing AMP thresholds are inadequate and inappropriate for several reasons. First, such thresholds are too loose to mitigate effectively the exercise of locational market power. In that regard, under the CAISO's existing local market power mitigation mechanism, resources having local market power can simply bid the expected zonal MCP plus $49.99/MWh to avoid being mitigated by AMP. This is inappropriate (and unjustifiable) in the local market power mitigation context because generally there is no (or very little) effective competition in constrained Load pockets. A supplier can bid well in excess of the applicable MCP and be reasonably assured that there will not be any competition for its Energy.

The MSC provided its opinion on the CAISO's existing LMPM measures in the MSC Opinion, described above. Specifically, the MSC stressed that stricter local market power mitigation measures are needed in California, and the measures approved by the Commission in the July 17 Order were wholly inadequate. The MSC recognized that "[s]ignificant amounts of local market power can still be exercised under this mechanism." MSC Opinion at 1. Indeed, the MSC concluded the AMP thresholds adopted by the Commission to mitigate local market power are "inappropriately loose". *Id.* at 3. The MSC also stated that "[a] generation unit owner can exercise a sizeable amount of local market power and still not trigger the bid mitigation process in the Commission's July 17th Order." *Id.*

Second, the limits on bidding flexibility that the Commission approved in the July 17 Order are significantly less protective of consumers than those which the Commission has approved for the Eastern independent system operators in order to address local market power. For example, in PJM, the bids of Generators called to operate for local reliability purposes are capped at: (1) the average LMP during a recent comparable period when the Generator was in merit order dispatch; (2) a level based on cost plus a 10 percent adder; or (3) a pre-negotiated rate. *See PJM Interconnection, L.L.C.*, 96 FERC ¶ 61,233 (2001) ("*PJM*"); *Atlantic City Electric Company, et al.*, 86 FERC ¶ 61,248 at 61,899 (1999). ISO New England's ("ISO NE") local market power mitigation applicable to "Other Congested Areas" ("OCAs") has significantly tighter thresholds than the thresholds the Commission approved for the CAISO. In that regard, in New England, a unit taken out-of-sequence due to a transmission constraint is subject to mitigation if its bid exceeds its reference price by $25 or 50 percent.[63] *New England Power Pool*, 100 FERC ¶ 62,287 (2002).

On the other hand, in California, a similarly situated unit is subject to mitigation only if its bid exceeds the zonal MCP (*i.e.*, a figure that generally exceeds a unit's reference price) by $49.99/MWh or 200 percent. Thus, there is a significantly greater opportunity for units in California to exercise local market power than similarly situated units can exert in PJM and New England. Given that there is a supply-demand imbalance in California and California has lower reserve margins than the Eastern independent system operators, there is no justifiable basis for the Commission to approve LMPM measures in California

[63] The Commission also approved specific, temporary mitigation measures for chronically constrained areas (Designated Congestion Areas or "DCAs"), whereby energy bids above a unit's safe harbor energy would be subject to possible mitigation. The safe harbor energy bid for units in a DCA that had a capacity factor of 10 percent or less during 2002 would be the sum of the unit's variable cost and the adjusted fixed cost adder. *Devon Power, L..L.C.*, 103 FERC ¶ 61,082 at P 33 (2003). The fixed cost adder for each such unit would be designed to recover the unit specific fixed costs (adjusted downward in the case of units covered by RMR contracts, to account for the costs recovered in the RMR contract) over the number of MW hours supplied in the preceding year. Further, the Commission concluded that the energy bids of peaking units are eligible to set the nodal energy price. Thus, when a peaking unit is called, all sellers will be able to receive a high market price and recover fixed costs. The Commission found that such methodology will enable seldom-run units to recover their fixed costs.

that are less protective than the LMPM measures the Commission has approved for other independent system operators.

Third, the CAISO's Commission-approved LMPM measures are also flawed because the Commission has applied the same market impact threshold to bids in constrained Load pockets that it applied to the State of California as a whole. There is no rational basis for this approach, nor is such an approach consistent with the Commission's treatment of other independent system operators.[64] In its July 17 Order, the Commission recognized that

> Transmission constraints or concentration of generation ownership may cause situations to arise in which the number of bids in certain areas of the grid or across transmission pathways is not sufficient to consider them competitive. Load pockets, generation pockets or local reliability problems resulting from such a situation may place a generating unit in a position to exercise market power.

July 17 Order at P 88. In other words, the Commission has found that suppliers can exercise market power when there are transmission and reliability constraints, *i.e.*, the only instances in which the LMPM measures would apply. It is unreasonable and counterintuitive for the Commission to approve the same market impact threshold both for circumstances where it acknowledges market power can readily be exercised and for circumstances where opportunities to exercise market power are generally less frequent. Clearly the former scenario requires that greater protections be in place.

The treatment the Commission has accorded the CAISO under these circumstances is inconsistent with the treatment that the Commission has accorded the NYISO and other independent system operators. For example, the Commission approved lower conduct and market impact thresholds to address locational market power issues in New York City when constraints exist than it did for New York State as a whole. *New York Independent System Operator, Inc.*, 99 FERC ¶ 61,246 at 62,039, 62,046 (2002). Both the Commission and the NYISO recognized that thresholds lower than those generally applicable to the system as a whole were necessary due to the increased potential for suppliers to exercise market power when constraints exist. Id. at 62,039-40, 62,046-48; *see also* Compliance Filing of the NYISO Regarding Comprehensive Market Mitigation Measures and Request for Interim Extension of Existing Automated Mitigation Procedure, Docket No. ER01-3155, *et al.*, pp. 38-41 and Affidavit of David Patton at 12-19 (March 20, 2002) ("NYISO AMP Filing"); and NYISO Limited Answer to Comments and Protests, Docket Nos. ER01-3155, pp. 2-4

[64] For all of the Eastern independent system operators, the Commission has imposed significantly stricter measures for mitigating local market power than it has for mitigating market power system-wide. In California, however, the Commission has imposed substantially similar mitigation measures for local market power and system-wide market power. That is neither factually justifiable nor legally sustainable.

(May 13, 2002). The NYISO succinctly set forth the reasons why stricter thresholds are necessary to address locational market power:

> [T]he frequency of congestion into and within New York City creates opportunities for a persistent exercise of market power, that is, for sellers to bid persistently right below the normal Market Mitigation Measures thresholds and realize monopoly rents at that level. Because that pricing could be sustained, it would become significant over time. Thus, while the In-City market and sub-load pockets will be subject to the same thresholds that are appropriate for unconcentrated areas of the New York Control Area when they are not experiencing persistent congestion, in the face of such congestion, these areas would be subject to potential market power abuse without additional mitigation in the form of tighter mitigation thresholds.

NYISO AMP Filing at 39-40. For the same reasons, the Commission must approve stricter market power mitigation provisions applicable to locally constrained areas than it has approved for California as a whole.

Unlike the Commission's treatment of the NYISO (and the other eastern independent system operators), the Commission approved the same market impact threshold to mitigate bids when local constraints exist as it has system-wide for the CAISO. It is axiomatic that an agency must conform to its prior practice, policy and decisions or explain the reasons for its departure from such precedent. *See United Municipal Distributors Group v. FERC*, 732 F.2d.202, 210 (D.C. Cir., 1984); *Greater Boston Television Cooperation v. F.C.C.*, 444 F.2d.841, 852 (D.C. Cir.), *cert. denied*, 403 U.S. 923 (1971) (agency must give reasoned analysis for departures from prior agency practice). The Commission has failed to conform to this mandate. Specifically, the Commission has not enunciated any valid reasons for granting the NYISO (and other independent system operators) tighter thresholds in circumstances where local market power can be exerted (compared to the thresholds that generally apply system-wide) but not the CAISO.

### 3. The CAISO's Proposed Local Market Power Mitigation Measures Are Just And Reasonable

The CAISO believes that effective local market power mitigation should result in nodal prices that approximate the prices that would result in a competitive market (*i.e*. prices should reflect the marginal cost of the highest cost unit dispatched). The CAISO does not believe that nodal prices should reflect a "scarcity premium" except in instances of true physical scarcity, *i.e.,* where there is insufficient supply to meet demand. In such cases, prices should reflect demand's marginal willingness to pay. The CAISO's proposed market design will permit this. The CAISO's proposed methodology for local market power mitigation – which is set forth in Section 2.7 of the amended Comprehensive

Market Design Proposal — reflects these principles, while still offering suppliers an opportunity to earn revenues that can be credited toward fixed cost recovery. Absent approval of LMPM measures such as those proposed by the CAISO herein, there will not be sufficient stakeholder and State policy maker support for the implementation of LMP in California.

Under the CAISO's LMPM proposal, system and local market power procedures will occur as part of several pre-processing IFM runs for determining RMR requirements. These pre-processing runs are referred to as the Pre-IFM Reliability and Market Power Mitigation runs ("Pre-IFM-RMPM") and will occur after all bids and schedules are submitted to the CAISO for each of the sequential markets (*i.e.*, the Day-Ahead, Hour-Ahead and Real-Time markets). The Pre-IFM-RMPM runs will be based on the CAISO's forecasted demand, rather than the scheduled and bid demand and will involve two runs-- one in which only competitive network constraints are enforced ("Pre-IFM-RMPM-CC run"), and a second run in which all network constraints are enforced ("Pre-IFM-RMPM-AC run"). Comparing the unit dispatch levels between the first and the second run will determine RMR requirements and the units that will be subject to local market power mitigation.

System market power mitigation ("System AMP") will be performed in the first Pre-IFM-RMPM with only the competitive network constraints enforced[65]. Specifically, units that violate the System AMP conduct thresholds will be mitigated to their reference levels and tested for market impact. The market impact test will require running the Pre-IFM-RMPM-CC a second time and comparing market prices from this run to the previous unmitigated run. If the bid mitigation does not produce a material impact on market prices, the initial unmitigated run will stand; otherwise, the mitigated run will stand. Bids and schedules from the final run will be used as a starting point in the next stage of the Pre-IFM-RMPM in which all network constraints are enforced ("Pre-IFM-RMPM-AC"). The schedules from the Pre-IFM-RMPM-CC will be protected from decremental adjustments in the Pre-IFM-RMPM-AC with penalty bids so that incremental adjustments in the Pre-IFM-RMPM-AC will be due to local reliability requirements and non-competitive network constraints only. Incremental Energy Bids from RMR units, including Condition 2 RMR Units will be considered in the Pre-IFM-RMPM-AC at the relevant contractual rates, if lower than any submitted bids.

[65] The initial list of non-competitive paths will be all of the transmission constraints modeled in the SCUC except Path 15, Path 26, the inter-ties, and local transmission constraints in pre-designated local generation pockets (*e.g.* Miguel substation). As the CAISO gains experience with LMP and the full network model, the CAISO will periodically review the competitiveness of transmission constraints and adjust the list of competitive paths accordingly. These assessments will examine whether frequently congested paths that are deemed "competitive" are in fact competitive, and whether frequently congested paths that are deemed "non-competitive" are in fact competitive. The methodology to be used for assessing the competitiveness of managing congestion on particular paths is set forth in Section 2.7 of the Comprehensive Market Design Proposal.

RMR and LMPM requirements are determined by comparing the unit schedules derived from the Pre-IFM-RMPM-CC and the Pre-IFM-RMPM-AC runs. Specifically,

(1) For RMR units, the Pre-IFM-RMPM-AC schedule will be the Minimum Reliability Requirement ("MRR") if this schedule is greater than the schedule in the Pre-IFM-RMPM-CC run. Submitted Energy bids from RMR units will be replaced for the corresponding MRR portion by the relevant contractual rates, if lower. Moreover, RMR units will be obligated to bid at least their unscheduled MRR portion in subsequent markets at no higher than their relevant contractual rates.

(2) For non-RMR units, the unit will be subject to LMPM if its Pre-IFMRMPM-AC schedule is greater than its schedule in the Pre-IFM-RMPM-CC. In such cases, only the portion of the unit's bid curve that is associated with the incremental schedule from the Pre-IFM-RMPM-AC run will be subject to mitigation.[66]

This approach provides effective local market power mitigation and is designed to minimize the extent of mitigation in the following two ways: (1) only the portion of the bid curve dispatched to resolve non-competitive congestion is subject to local market power bid mitigation; and (2) the mitigation is based on the higher of the highest accepted portion of the bid curve in the IFM-RMPM-CC run or the unit's Default Bid. Therefore, a unit will not be mitigated to its Default Bid if its highest accepted bid in the competitive run exceeds its Default Bid. All other portions of the unit's bid curve will remain unmitigated unless such bids were mitigated under System AMP. For RMR Units, MRR quantities will be mitigated to the lower of the submitted market bid (if applicable) or the RMR Contract variable cost. Market bids will be used for bid quantities above the MRR. The mitigated bid curves derived from the pre-IFM-RMPM runs and the MRR will be passed on to the Final IFM, which is based on submitted demand schedules and bids, to determine final schedules and prices. Bids mitigated in the Pre-IFM-RMPM runs will be eligible to set the LMP in the Final IFM.

Resources subject to LMPM would be mitigated to Default Energy Bids based on the following criteria (listed in order of preference depending on the availability of information): (1) the unit's variable cost for gas fired units, plus a 10 percent adder and, for all other resources, the lower of the mean or median of the resource's market-based bids during the previous 90 days when the unit was dispatched in economic merit order; (2) a weighted average of the appropriate

[66] The CAISO may need to mitigate an small additional portion of the bid curve (*e.g.* 1-2 MW) to ensure that unmitigated portion of the bid curve does not effect the final determination of LMPs (*i.e*. LMPs are determined based on the cost of meeting an additional MW of load at each location, not on forecasted load).

competitive region prices during the previous 90 days when the resource was dispatched in economic merit order; or (3) a negotiated price.

The proposed LMPM measures are similar to those employed by PJM (as discussed *supra*). PJM's LMPM measures – which are the strongest LMPM measures employed by any existing independent system operator – have worked effectively for several years. Indeed, Commission has recognized that PJM's measures for mitigating local market power "serve to minimize opportunities for the sustained exercise of market power". 86 FERC at 61,902. Further, although the MSC supports Commission approval of LMPM measures that are different than those being proposed by the CAISO herein, the MSC is generally supportive of the CAISO's use of the PJM local market power mitigation measures. *See* Attachment D at 3. The MSC also has indicated that the PJM approach comes much closer to satisfying the properties of its preferred approach than does an AMP-type LMPM mechanism. LMPM Opinion at 10.

Similar to the CAISO's proposal, PJM's LMPM process involves two passes of the scheduling software -- a first pass with only competitive interface constraints enforced, and a second pass with all transmission constraints enforced. Units committed in the second pass that were not committed in the first pass are automatically cost-capped. Moreover, units that are committed in both passes but which submit hockey stick bids are subject to cost capping. The CAISO notes that in June 2001, PJM filed a proposed amendment to its operating agreement and tariff that would extend PJM's existing authority to cost-cap must-run units[67] beyond the day-ahead market to the real-time market as well. PJM stated that its experience over the last few years showed that it also needed the ability to cost-cap must-run units in real time, in order to prevent the exercise of market power if an unexpected transmission constraint should occur, so as to render, unexpectedly, a resource a must-run unit.[68] Consistent with

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[67] PJM defines must-run units as "generation resources that…as a result of transmission constraints…must be run to ensure the reliability of service in the PJM control area." *PJM FERC Electric Tariff* at 249.

[68] The Commission approved PJM's request, stating:

> [i]f, however, a transmission constraint occurs so as to make that unit a must-run resource, the generator could earn its high price, and that price would also become the LMP for the particular load pocket for that day. As PJM notes in its answer, this scenario has, in fact, occurred. PJM's MMU thus concluded that PJM should have the authority to cost-cap must-run units in real time in order to prevent the exercise of market power, and this proposal was approved by PJM's stakeholders. We find that PJM has persuasively demonstrated that, absent the authority to cost-cap in real time, consumers would be subject to the exercise of market power by generators, and that PJM requires authority to cost-cap must-run units in real time to prevent the exercise of market power in real time.
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> * * *
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> While no one (including PJM) can predict precisely when and where a transmission constraint may occur in real time, as stated above, a generator located within a load pocket can assume that a transmission constraint may

PJM's statements and the Commission's orders approving PJM's LMPM measures, the Commission should grant the CAISO local market power mitigation measures similar to those which it has granted PJM. [69]

Certain suppliers have argued that less stringent local market power mitigation is warranted in California due to the alleged lack of market opportunities for suppliers to recover their annual fixed costs. The CAISO strongly disagrees with this argument. As discussed *supra* in Section III.C, most suppliers have ample opportunities to recover their annual fixed costs through long-term bilateral contracts[70], through short-term bilateral contracts with the three IOUs, through spot-market energy sales during hours when the unit receives an MCP above its marginal cost (*i.e*. infra-marginal), and through A/S capacity sales. Further, the CPUC is in the process of developing a resource adequacy plan. This should result in additional opportunities for suppliers to contract with the IOUs who need satisfy any resource adequacy obligation they may have.

In addition, the majority of units located in significantly constrained areas (*e.g*. San Francisco) are operating under RMR contracts which the CAISO anticipates will continue absent an alternative. The CAISO notes that it currently provides RMR Contracts to units that likely would be most impacted by the LMPM proposal.

In any event, the CAISO believes that its LMPM proposal provides ample market opportunities for generating units to recover their annual revenue requirements. Specifically, the LMPM is selective in that it only applies in hours where a non-competitive path is congested and only to units that have to be

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occur so as to make its unit a must-run resource. Moreover, as described above, a generator need not predict with certainty that it will be designated a must-run resource in order to be able to exercise market power – it need only bid its generation into the market at an excessively high price, and over the course of time, it will, likely, at certain times, be designated a must-run resource. Thus, the fact that generators cannot predict exactly when they might be designated a must-run resource does not eliminate the need for PJM to be able to cost-cap units in real time so as to prevent must-run generators from exercising market power. *PJM* at 61,936.

[69] Parties might argue that Generating Unit owners cannot predict transmission constraints and, therefore, they are unable to exercise market-power in Real-Time. As indicated above, the Commission rejected that very argument in *PJM*. *See PJM* at 61,936. Further, the CAISO's experience has shown that local market power situations typically arise due to the outage of a major Generating Unit or transmission facility and that such outages typically last several days. Because these events are well known to the market, it is easy for Generating Unit owners to predict when they can successfully exercise local market power.

[70] As the Commission is well aware, California has signed over $40 billion in long-term contracts with energy suppliers, and IOUs continue to pursue additional contracts. Thus, there are ample market opportunities for unit owners to recover fixed costs outside of the limited periods that they would be subject to local market power mitigation.

dispatched up because of the non-competitive constraints. The CAISO proposes that the mitigated bid include a 10 percent adder for thermal units as an extra measure to provide for the recovery of a unit's variable costs. Moreover, such units are only mitigated for the positive incremental dispatch associated with relieving congestion on the non-competitive constraint and only to the extent that their incremental bid exceeds the highest bid dispatched in the prior pre-IFM run in which only competitive constraints are enforced. Units that are mitigated are not precluded from earning the locational marginal price. Thus, to the extent they are infra-marginal, there will be opportunities for fixed cost recovery even during mitigated periods. Under these circumstances, there is no basis for the Commission to reject the CAISO's proposal on the grounds that suppliers in California lack an adequate opportunity to recover their fixed costs.

To the extent a non-RMR Unit has its bids frequently mitigated under the CAISO's proposed LMPM measures, and the resource owner believes there is not a reasonable opportunity to recover the resource's legitimate going forward fixed costs through other means, the CAISO would be willing to consider the *possible* need for an additional, fixed-cost compensation mechanism in order to address demonstrated revenue adequacy concerns raised by resources that do not have RMR contracts. The CAISO will evaluate the need for such compensation on a case-by-case basis, considering the following factors: (1) whether the unit is needed for local reliability services; (2) the extent to which the resource has and is likely to continue to be frequently mitigated under the LMPM measures; (3) whether the resource is currently covered under an existing RMR Contract; (4) whether the resource owner has a long-term CERS contract or other bilateral contracts; (5) potential revenues from spot-market transactions in the CAISO energy and A/S markets; and (6) the unit's annual going forward fixed costs. The costs associated with any cost-based compensation mechanism would be allocated to all Demand within the applicable Load Aggregation Zone.

The CAISO would closely coordinate such additional fixed compensation with any CPUC resource adequacy plan to avoid duplicate contracting. The CAISO strongly favors considering separate fixed cost uplifts on a case-by-case basis, instead of allowing mitigated bids to include generic bid adders for fixed cost recovery. Such an adder is extremely inaccurate and will lead to excessive payments to units in constrained areas that otherwise have opportunities to recover their costs absent such an adder. Finally, because the units that would be most frequently subject to LMPM are likely to have RMR contracts already, the CAISO does not expect many units to require special additional fixed cost compensation. Nonetheless, the CAISO is willing to consider such additional compensation if the Commission grants the CAISO its proposed PJM-like LMPM approach.

In its White Paper, the Commission points out that "mitigation measures must work together with measures on resource adequacy to ensure that the measures do not suppress prices below the level necessary to attract needed investment in infrastructure in the region"[71] and the "types of mitigation tools and the triggers and consequences of mitigation should be tailored to the needs of the region."[72] The CAISO believes its LMPM proposal, coupled with a commitment to consider fixed cost compensation for resources that do not have RMR contracts and whose bids are likely be mitigated frequently under the proposed LMPM measures, will ensure revenue adequacy for suppliers. Further, the CAISO's LMPM proposal, in conjunction with long-term resource adequacy planning and capacity contracts, will provide a sufficient mechanism to incent local infrastructure investment. Consistent with the Commission's prior determinations that resources should not rely primarily on the spot market for fixed cost recovery,[73] the CAISO believes that long-term capacity contracts should be the primary vehicle for attracting new investment in locally constrained areas. Suppliers should not be relying on a Real-Time spot market that serves only a *de minimus* percent of total load in the State for recovery of their fixed costs. Stated differently, no one can credibly argue that significant investment decisions that depend on a reasonable opportunity to recover total costs will be driven by prices in the CAISO's small Real-Time energy market. In particular, significant infrastructure investment decisions will not be impacted by the level of mitigated prices due to the CAISO's LMPM measures given that such mitigation will occur only in certain limited circumstances.

Under these circumstances, the CAISO's proposed LMPM measures, when viewed in the context of the overall market design and existing levels of long-term forward contracting are just and reasonable. They successfully balance the need to mitigate the exercise of local market power by suppliers, while providing adequate market opportunities for suppliers to recover their annual fixed costs.

#### 4. If The Commission Does Not Approve PJM-Style Mitigating It Should Approve The CAISO's Alternative LMPM Measures

In addition to considering the PJM methodology for mitigating local market power, the CAISO also considered other options including: (1) the methodology

[71] "White Paper, Appendix A at 11.

[72] White Paper at 9.

[73] The Commission has recognized that "bilateral contracts should be the principal means by which generators recover their total costs."[73] *See Midwest Independent Transmission System* Operator, 102 FERC ¶ 61,280 at P 47 (2003); *San Diego Gas and 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 ¶ 61,115 at 61, 364 (2001). Accordingly "generators should be willing to sell any residual real-time energy for any price at or higher than their marginal cost" *Id*

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in place in the NYISO, and (2) the methodology in place in ISO New England.[74] With respect to local market power mitigation in the NYISO, the NYISO sets In-City load pocket conduct and impact thresholds according to a formula[75] that is proportional to the number of congested hours experienced over the preceding 12-month period. An In-City bid will be mitigated if it exceeds the reference level by more than two percent.[76] *New York Independent System Operator, Inc.,* 99 FERC ¶ 61,246 at 62,046 (2002).

Although the NYISO mechanism for mitigating local market power is superior to the LMPM measures that the CAISO currently has in place, the CAISO – as well as the MSC -- believe that the PJM measures will be more effective in mitigating local market power. For example, the NYISO approach basically guarantees that a supplier can exercise local market power up to the specified conduct threshold. Moreover, under the NYISO local market power AMP, bids that violate the conduct and market impact tests would be mitigated to reference levels that are predominately based on accepted bids over the previous 90-days. Having local market power mitigation based on bid-based reference levels increases the incentive strategically to bid high in order to drive up the reference price. Specifically, generators that expect to be infra-marginal will have a strong incentive to bid just below the expected marginal bid so they will have a higher accepted bid to apply to the reference price calculation. While it is true that such incentives exist under the global AMP provisions that the CAISO currently has, they are not as great because the opportunities to exercise system-wide market power are generally less frequent than the opportunities particular generators will have to exercise local market power. For these reasons, the CAISO believes that the NYISO approach does not provide adequate protection against local market power. Moreover, implementing bid conduct and market impact tests for both System and Local market power AMP mitigation will result in an excessively complicated market software system that will require multiple SCUC runs. Local market power mitigation is better implemented through a simpler and more transparent process, *i.e.*, like the PJM approach.

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[74] The Commission has recently approved local market power mitigation measures for MISO that apply to Narrow Constrained Areas ("NCAs"). *Midwest Independent Transmission System* Operator*, Inc.*, 102 FERC ¶ 61,280 (2003). Thresholds in NCAs are pegged to a unit's reference level, plus a fixed cost adder that reflects the fixed costs that would be recovered by a hypothetical new peaking unit. Reference levels would be calculated using the following methodologies (in order of preference): (1) the lower of mean or median of the unit's accepted bids for the last 90 days, adjusted for fuel prices; (2) the mean of the LMP at the unit's location during the lowest priced 25 percent of the hours that the unit was dispatched in the last 90 days, adjusted for fuel prices; or (3) a level determined in consultation with the owner.

[75] Load Pocket Threshold = 2% * Avg. Price * 8760.

[76] The two percent is the maximum sustained price increase that a bidder can realize over the course of a year. As the number of congested hours increases, the conduct and impact thresholds would decrease to ensure that annual exposure to price increases is limited to two percent.

Likewise, the local market power mitigation measures that the Commission has approved for ISO New England (applicable to DCAs) and the Midwest ISO (applicable to NCAs) are not appropriate. Indeed, in the LMPM Opinion, the MSC strongly recommends against the inclusion of any adder or CT proxy in any mitigated bid level. LMPM Opinion at 8-9. The Commission provided the following two reasons for adopting the mitigation measures applicable to NCAs on the MISO system: (1) such measures provide appropriate price signals for the entry of new supply; and (2) such measures provide an adequate opportunity for generators to recover their fixed costs. The CAISO disagrees with the Commission's reasoning for several reasons. First, the mitigation measures approved for MISO (and ISO NE) assume that there is insufficient infrastructure (generation and transmission) in the constrained area when in fact there may be ample generation, but such generation is owned by only one or two companies. That is the case in numerous locales in California. In such instances, there is not a need for additional generation and/or transmission investment; rather, there is a need to mitigate the local market power of the existing generator owner(s). Second, new generation investment decisions are not based primarily on locational spot prices. Siting decisions are predominately based on environmental considerations (especially in California), the availability of natural gas supplies and electric transmission infrastructure and the availability of long-term generation contracts. The Commission's rationale supporting MISO's LMPM measures is inconsistent with the Commission's long-standing position that suppliers should recover their fixed costs or through bi-lateral contracts not in Real-Time energy markets. Third, in locations that are or will be supply deficient, the LSE in that area has obligation to serve load and, therefore, an obligation to make the necessary infrastructure investments to ensure it can reliably serve its load. The ultimate price signal for LSEs is the potential economic and social impact of blacking out a densely populated load area. LSEs have a strong incentive and regulatory obligation to avoid such impacts. Fourth, the MISO mitigation measures, which essentially are akin to the Commission defining an "acceptable level of local market power", constitute an imperfect mechanism for recovering annual fixed costs because it will invariably mean excessive payments for some generators and inadequate revenues for others. Local market power bid mitigation should seek to simulate the prices that would result in a competitive market (*i.e*. marginal cost pricing). If such mitigation prevents certain units that are critical for meeting local reliability needs from recovering their annual fixed revenue requirements, uplifts should be provided through an annual capacity contract (*e.g.* RMR or alternative contracts with LSEs).

The CAISO also submits that the mitigation measures the Commission has approved for ISO NE applicable to DCAs are inadequate and inappropriate. Such mitigation measures would enable all units at a node to collect the high price set by a peaking unit (which price is purportedly necessary to enable the peaker to recover its fixed costs). This is unnecessary and illogical given that the concern being addressed is whether seldom-used peaker units can recover their fixed costs. The approach approved by the Commission would result in an unjustifiable windfall for units that are dispatched on a more regular basis. The CAISO submits that, if the Commission is concerned about cost recovery for peakers, it should consider adopting an approach that would provide some type of capacity payment to a peaker in order to keep it whole. This is a more targeted approach that addresses the specific concerns expressed by the Commission.

In any event, recognizing that the Commission might find that a less effective [77] AMP approach is appropriate for purposes of local market power mitigation – and not the PJM-like approach being proposed in MD02 -- the CAISO is offering an AMP approach as a less preferred alternative to its primary proposal. The alternative AMP approach would employ conduct and market impact thresholds that are tighter than the CAISO's existing AMP thresholds. However, the CAISO cautions that the Commission should consider the CAISO's alternative LMPM proposal *only* if it first finds that CAISO's primary LMPM proposal is not just and reasonable. The Commission cannot simply reject the CAISO's primary proposal because it believes that the CAISO's alternative proposal is a "better" alternative.[78] Stated differently, if the CAISO's primary proposal is just and reasonable, the Commission must approve such proposal even if it believes that the alternative proposal also is just and reasonable. In the event the Commission finds the primary proposal to be unjust and unreasonable, the CAISO urges the Commission to adopt the alternative proposal as a necessary measure to mitigate the exercise of local market power in a nodal pricing regime.

As discussed above, the CAISO is concerned that mitigating resources that have local market power to a bid-based reference level will create incentives for unit owners to bid up their reference levels strategically. Therefore, if the Commission were to adopt the CAISO's alternative approach, then the CAISO strongly recommends that the mitigated bid used in this procedure be cost-based, *i.e.*, Default Bids as proposed under the CAISO's preferred approach. The CAISO also recommends that conduct thresholds be set at the lower of $10/MWh or 20 percent above the unit's Default Energy Bid and market impact

[77] The CAISO is concerned that implementing an AMP approach for LMPM in the context of a nodal market will be extremely complicated and may not be feasible within the CAISO market timelines given all the other additional software runs to accommodate, *inter alia*, System AMP, RMR Pre-Dispatch, and the CRR scheduling priority.

[78] *See New England Power Company*, 52 FERC ¶ 61,090 at 61,336 (1990), *reh'g denied*, 54 FERC ¶ 61,055, *aff'd Town of Norwood v. FERC* 962 F.2d 20 (D.C. Cir. 1992); *citing City of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984), *cert. denied*, 469 U.S. 917 (1984) (utility need establish that its proposed rate design is reasonable, not that it is superior to alternatives); *OXY USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995) ("[T]he Commission may approve the methodology proposed in the settlement agreement if it is 'just and reasonable'; it need not be the only reasonable methodology or even the most accurate").

thresholds be set at the lower of $10/MWh or 20 percent effect on LMPs.[79] Although these alternative LMPM measures would not be as effective at mitigating local market power as the PJM measures, they will be more effective than the existing measures. As with the PJM approach, such measures would allow suppliers to earn revenues in excess of marginal costs. As a final matter, the CAISO notes that the MSC does "not recommend AMP style approaches to local market power mitigation unless the conduct thresholds are reduced to within ten percent of the unit's filed marginal cost, the impact thresholds are substantially reduced or eliminated, and an additional mechanism is used to determine whether a unit possesses local market power so that the tighter LMPM conduct and impact thresholds are applied to a unit's bids." LMPM Opinion at 9-10.

### C. Congestion Revenue Rights[80]

#### 1. Summary of the CAISO's CRR proposal

Adopting the LMP paradigm requires the CAISO to replace the existing Firm Transmission Rights ("FTRs"), which are defined in terms of specific transmission paths, with a "source-to-sink" (often referred to as "point-to-point")[81] congestion hedging instrument.[82] The CAISO will adopt the term CRRs to distinguish this redesigned source-to-sink congestion hedging instrument from today's path-specific FTRs.[83] The CAISO's CRR proposal is set forth in Section 2.3 of the amended Comprehensive Market Design Proposal. A source-to-sink CRR specifies as its "source" a single network node or set of nodes (such as a

[79] Details regarding how such an approach could be accommodated in the CAISO's proposed IFM-RMPM runs is provided in section 2.7 of the CAISO's amended Comprehensive Market Design Document.

[80] The CAISO has adopted the term Congestion Revenue Rights from the Commission's SMD NOPR, rather than retaining the term "Firm Transmission Rights" or "FTRs' that was previously used for this concept.

[81] The term "source-to-sink" is preferable to "point-to-point" and will be used throughout this document as the generic term for the congestion hedging instrument associated with the LMP congestion management paradigm. The term "source-to-sink" is more compatible with the notion that source and sink may be a specified set of network nodes, whereas "point-to-point" tends to be understood as requiring that the source and sink must each be single network nodes.

[82] Because CRRs are a congestion hedging instrument, the revenue entitlement to CRR holders will not include the cost of transmission losses.

[83] Another important contrast between today's FTRs and the proposed CRRs is that the quantity of today's FTRs available for a given transmission path is determined independently of the quantities of FTRs available for other transmission paths. In conjunction with the source-to-sink CRR model under LMP, the CAISO must perform a simultaneous feasibility test ("SFT") to determine the quantities of CRRs that can be released for the entire grid via the allocation and auction processes described below.

trading hub) at which power is injected or delivered to the transmission grid, and as its sink a single network node or set of nodes (such as a load aggregation zone or a trading hub) at which power is withdrawn from the transmission grid.[84]

The CAISO proposes to allocate CRRs to LSEs on behalf of loads within the CAISO control area based on historic quantities and geographic distribution of their loads and anticipated distribution of their supply resources. Subsequent to the allocation process, the CAISO will offer additional CRRs, to the extent available, to all qualified bidders through an auction process. These CRRs will be "Obligations", which impose a cost on the CRR Holder when congestion is in the opposite direction of the CRR, as opposed to "Options", which do not impose such a cost. The CAISO proposes to offer (*i.e.*, allocate and auction) CRRs based on two different term lengths – one-year and monthly. Distinct CRRs may be requested and released for peak and off-peak periods. Parties with ETCs that convert to CRRs will have the choice of receiving CRR "Obligations" or CRR "Options". Self-schedules that are explicitly associated with CRRs in the Day Ahead market will have a higher curtailment priority at the associated sinks than non-ETC schedules without associated CRRs.[85]

In general, the source of a CRR will be either a single injection node or inter-tie point or a CAISO-defined Trading Hub. However, the CAISO will also offer Network Service CRRs ("NS-CRRs") to enable LSEs that can serve their load from multiple supply nodes to obtain a bundle of CRRs that provide an optimal congestion hedge at least cost. To obtain a NS-CRR, a market participant will specify a set of injection nodes or inter-ties and assign nodal quantity bids or priorities to indicate the preferred distribution of rights over these nodes and acceptable adjustments in case the preferred distribution is not feasible. The CRR allocation procedure will provide the preferred distribution if possible, or it can optimize the distribution to provide the set of rights most valuable to the participant. Once the NS-CRR is issued, the distribution factors for the injection nodes will be fixed. Holders of NS-CRRs may unbundle such NS-CRRs into single-injection node CRRs for sale in the CAISO auction or for secondary trading, consistent with the distribution factors defining the NS-CRR.

84 The CAISO will explore the possibility of offering path-specific or "flowgate" rights, in addition to source-to-sink CRRs, if there is a need for this type of instrument in the future. In its comments on the SMD NOPR, the CAISO explained that the CAISO should decide, through a stakeholder process, when it is appropriate to offer flowgate rights or source-to-sink CRR Options. The decision should be based on technical feasibility, significant market participant interest in the products and a determination whether the benefits outweigh the time and resources necessary to implement the new products. An efficient integrated forward and real time energy market can be achieved without an expedited implementation of options and flowgate rights. *See* CAISO SMD Comments at 55.

85 Such (demand-side) CRR schedule protection can be invoked only in conjunction with initially balanced preferred schedules (although the CAISO's congestion management process will not enforce any requirement that the final schedule be balanced).

Of course, as a result of such trading, the quantities and distribution factors of the NS-CRR will be revised to reflect the remaining rights.

Under the LMP paradigm each nodal price can be decomposed into three components for energy, congestion, and transmission losses. The congestion components of the nodal energy prices produced by the IFM will be the basis for congestion charges.[86] Thus, the congestion charge for injecting 1 MWh at node A and withdrawing 1 MWh at node B will be the congestion component of the energy price at node B minus the congestion component of the energy price at node A. This is the price difference that will be hedged by CRRs. CRRs will not protect the holder from nodal price differences due to transmission losses.

Settlement of all payments and charges related to CRRs will be based on Day-Ahead IFM prices. Also, the demand-side scheduling priority of CRRs will apply only in the Day-Ahead market. CRRs will not be applicable to the Hour-Ahead and Real-Time markets.

As a final matter, the CAISO recognizes that the Commission, in its White Paper, indicated that it would "look to regional state committees to determine how such [CRRs] should be allocated to current customers based on current uses of the grid." White Paper at 5. The CAISO's final resolution of CRR allocation issues will be determined in a manner consistent with the White Paper. *See supra* Section II.B.1 hereof.

### 2. CRR Design Issues

#### a. CRR Obligations vs. Options

The proposed CRR design will be primarily an "Obligations" instrument, in contrast to today's "Options" FTRs. *See* Paragraph 78 of the amended Comprehensive Market Design Proposal. With CRR obligations, a CRR holder is liable for congestion charges when congestion is in the opposite direction of its CRRs. As long as the CRR holder schedules in accordance with its CRRs, the payment for counter-flow scheduling will offset the liability of the CRR holder's obligation. One exception to the Obligations model is that ETC rights holders who convert their rights to CRRs will have a choice of receiving either CRR Options or CRR Obligations.

The CAISO has determined that Obligations should be the primary form of CRR because Obligations allow for a more efficient and extensive allocation of rights than is possible with CRR Options, while still maintaining revenue adequacy. By explicitly incorporating the effects of counter-flow schedules on net line flows, CRR Obligations allow for a greater release of rights, while still

[86] Because the energy component is the same for all nodes, another way to view the locational price used for deriving applicable congestion charges and CRR settlements is the LMP minus the loss component of the LMP.

enforcing simultaneous feasibility. CRR Options, on the other hand, can only be released up to the level of grid transfer capability because, absent the liability for congestion charges associated with Obligations, releasing CRR Options based on the netting effects of counter flows will result in a systematic congestion revenue shortfall.

Although the CAISO is proposing initially to offer only Obligations CRRs to LSEs and other market participants, the CAISO is willing to offer Options CRRs to the entire market in the future if the CAISO determines that it is technically feasible to do so on such a large scale, and the benefits outweigh the additional costs and complexity. This position is consistent with the SMD NOPR which does not require independent transmission providers ("ITPs") to offer Options CRRs initially, but states they should do so once Options CRRs are technically feasible, and once the ITP gains experience under SMD and tests the various CRR instruments. SMD NOPR at 248.

#### b. Physical Scheduling Priority For CRR Holders

Substantial debate over many months on the inter-related issues of self scheduling and a CRR scheduling priority has led the CAISO to develop a revised proposal which the CAISO is confident will meet the needs of market participants. In the May 1, 2002 filing, the CAISO proposed to provide a physical scheduling priority in the Day-Ahead IFM to balanced CRR schedules, and to keep those schedules in balance if they required non-economic adjustment to relieve Day-Ahead congestion. Upon further consideration, the CAISO realized that this proposal – particularly the requirement to keep CRR schedules balanced under non-economic adjustment – could severely constrain the CAISO's ability to perform realistic Day-Ahead schedule adjustments for congestion management. In particular, the CAISO's objective of allocating CRRs to LSEs to fully hedge loads against congestion costs, combined with the fact that most LSEs prefer to use their own resources (owned or under contract) to serve their own loads rather than trade in the spot markets, could result in most schedules being submitted as self schedules, *i.e.*, without energy bids needed to perform economic adjustment for congestion management. If this occurred, the CAISO would constantly be forced to resort to non-economic adjustment of CRR schedules to manage congestion.

Although non-economic adjustment is acceptable as an occasional back-stop when economic bids are insufficient, its regular occurrence would defeat a primary purpose of MD02, namely, to establish an economically efficient bid-based allocation of transmission simultaneous with the locational pricing of energy. Moreover, non-economic adjustment of CRR schedules would typically result in two undesirable outcomes: (1) shifting of load from the Day-Ahead to subsequent markets;[87] and (2) unrealistic non-economic decremental re-dispatch

[87] This would be a direct result of the requirement to keep CRR schedules in balance, which would essentially amount to enforcing today's already onerous "Market Separation Rule" in

of Must Take resources (such as nuclear and Qualifying Facility contract power) which, in reality, are going to perform in accordance with their submitted self schedules irrespective of their Day-Ahead re-dispatch by the CAISO, thereby ultimately exacerbating Real-Time congestion. These outcomes would further undermine the objectives of MD02 by increasing the volume of load in the Hour-Ahead and Real-Time markets and exacerbating Real-Time operational complexity.

With additional input from market participants the CAISO determined that restricting the CRR scheduling priority to the demand side of CRR schedules would meet market participants' needs, as well as provide the CAISO the needed flexibility to adjust supply resources to perform realistic congestion management. *See* Paragraph 89 of the amended Comprehensive Market Design Proposal. A demand side scheduling priority will meet LSEs' needs by ensuring that their load is scheduled in the Day-Ahead market and served at least cost, without risk that their load may be curtailed while their own resources are scheduled to serve load of other LSEs. It will address the CAISO's concerns about performing realistic congestion management by: (1) enabling SCs to submit energy bids on the supply side of CRR schedules while still preserving the CRR priority for the demand side;[88] (2) not requiring the CAISO to treat all supply resources submitted with CRRs the same, without regard to Must Take status; and (3) minimizing the need to shift load from Day-Ahead to subsequent markets to manage congestion.

Thus, under the CAISO's proposal, SCs who want to utilize CRR Day-Ahead scheduling priority must submit preferred schedules that are initially balanced. Allowing an unbalanced load to use a CRR scheduling priority undermines the intent of that priority by allowing such unbalanced load to compete on an equal basis for supply designated to serve an initially balanced load schedule with the same CRR priority. In addition, the CRR-protected schedule must specify the same source and sink as the CRR being utilized[89], and must not have any decremental energy bids on the demand side of the schedule.[90] In particular, SCs must bring to the market adequate supply to serve

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managing congestion on a detailed network model. Because the CAISO would not be able to re-dispatch supply resources across SC schedules, the only remaining option for congestion relief would be for the CAISO to curtail load, thereby exposing load to Day-Ahead RUC charges and driving load to the more volatile Hour-Ahead and Real-Time markets.

[88] This will benefit the SC by enabling its load to be served more cheaply from the market, and will benefit the market as a whole by encouraging a deeper pool of bids for economic congestion adjustment.

[89] Because non-ETC loads can schedule only at Load Aggregation Zones, they must have CRRs with sinks at the Load Aggregation Zone level to use the CRR scheduling priority.

[90] Putting decremental bids on the demand side of a CRR schedule effectively voids the CRR protection for the amount of load covered by the decremental bids.

the load they wish to protect with the CRR. This requirement is intended to reinforce the primary objective articulated by market participants as the basis of their need for CRR scheduling priority, namely, to ensure that their own resources are utilized to serve their own load. If a LSE with CRRs were allowed to submit only a load self schedule with no accompanying supply, that load would compete with other CRR load for available generation in the event of non-economic curtailment.

Some market participants suggested eliminating the CRR scheduling priority altogether arguing that CRRs should be purely financial instruments. Many LSEs opposed this due to a concern that, without a CRR scheduling priority, the self-scheduled demand (*i.e.,* sink) side of their initially balanced preferred schedule might get curtailed in the Day-Ahead congestion management process, and the supply (*i.e.,* source) side schedule used to serve some other entity's Day-Ahead load, thereby exposing the LSE to Hour-Ahead and Real-Time price uncertainties and under-scheduling charges. The CAISO considered the possible elimination of the CRR scheduling priority and decided against it for several reasons. The primary argument in favor of some form of scheduling priority is that most LSEs have retained generation and contractual arrangements for energy and capacity that they want to serve their own load. A demand-side Day-Ahead CRR priority allows LSEs to do this. Absent a CRR priority, the load side of a balanced schedule would have to bid at extremely high prices in order to avoid having to compete with other unbalanced loads.

Further, the SMD NOPR contemplates that CRR holders will have a scheduling priority for service between the receipt point and delivery point. SMD NOPR at P 243. The White Paper also states that "RTOs and ISOs that use locational pricing to manage congestion would be required to make FTRs available to customers", and that such "FTRs allow customers to schedule service according to the paths specified in their rights, with no risk of congestion charges", and that "[t]here also be no risk of curtailment absent a force majeure event such as the loss of a transmission line." White Paper at 10. The proposed scheduling priority is consistent with these principles. As a final matter, the CAISO notes that the Commission has previously approved a scheduling priority for FTR holders in California; so, the CAISO's proposal is not an entirely new concept in California.[91] Eliminating the scheduling priority in its entirety, however, would constitute a significant change for market participants.

[91] In its order accepting the CAISO'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 CAISO'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. Although the previous FERC ruling pertained to FTRs under a contact path paradigm, some of the elements leading to that conclusion apply in the new market design. Accordingly, although the instant filing

### c. Single Balancing Account For CRR Revenue Surpluses and Deficits

In any given hour, the amount of congestion revenues may not exactly equal the settlement of all CRRs. This is because CRRs are released based on a single snapshot of system conditions, and these conditions in fact may vary from hour to hour. In order to maintain the hedge as much as possible, the CAISO will create a balancing account that accumulates the excess revenues generated in hours when total net congestion charges exceed required net CRR payments, and then distributes these revenues to keep CRR holders whole in hours when congestion charges are inadequate. Funds in the balancing account will be disbursed at the end of each month to CRR holders who were not fully compensated during the month. In addition to monthly clearing, there will be a yearly clearing of the balancing account. Any surplus funds in the balancing account at the end of the year will be allocated to CRR owners in proportion to their gross un-recovered annual shortfall. Any remaining surplus at the end of the year will be paid to PTOs.

If the balancing account is short at the end of the year, no additional payments or charges will be made. In this case, it indicates that CRR holders have not been fully compensated for their CRR entitlement over the 12-month period. In order to reduce the probability of insufficient funds to pay off CRR financial entitlements, the CAISO's CRR allocation and auction design attempts to strike a balance between the competing objectives of maximizing the release of CRRs and the degree of certainty regarding revenue adequacy. CRR studies currently underway at the CAISO will provide estimates of the quantities of CRRs that can be allocated to control area loads and released through the auction process, taking into account the requirement to honor non-converted ETCs and allocate CRR Options to converted ETCs that request them.

The CAISO proposes to utilize a single balancing account (rather than separate PTO-specific accounts) for any surplus or deficit of CRR revenues over the year. There are several reasons for this recommendation. First, it is important to realize that unplanned transmission outages and derates constitute the primary reason for CRR revenue inadequacy in any given hour, because they reduce energy flows (and, hence, the amount of CRR revenue collected), while increasing the cost of congestion (and hence the total amount of congestion payments due to CRR holders). Given this fact, some parties argued that an effective incentive for PTOs to manage transmission maintenance more effectively and minimize such events would be to have PTO-specific balancing accounts and to hold each PTO responsible for making up any shortfall of funds

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does not retain the identical CRR priority scheme that currently exists under the Tariff, it does include a revised scheduling priority. Consistent with its prior decision, the Commission should approve the proposed demand-side CRR scheduling priority.

at the end of each year. Ultimately, however, the LMP/CRR Working Group consensus was that having a separate balancing account for each PTO would not provide an effective incentive for PTOs to maintain their transmission systems. The group felt that, although PTOs should be encouraged to minimize outages that are within their control, a separate balancing account for each PTO would not be the means to achieve this objective because many transmission de-rates are not within the control of the PTOs. Also, the CAISO already has in place an effective transmission maintenance program and coordinates with the PTOs on transmission outage schedules in order to minimize their market interference and impact.

Second, the LMP/CRR Working Group generally believed that the probability of CRR owners obtaining a better hedge is greater with a single balancing account than with multiple accounts due to the spreading of any shortfall over the entire system. Third, a separate balancing account for each PTO would be difficult to implement and would be subject to protracted disputes among PTOs because the determination of causation would be difficult to establish. This is because, in the LMP context, an outage or derate of any given transmission line will have impacts on nodal prices and congestion costs throughout the grid. Finally, a single balancing account is more in line with the CAISO's long-term goal of having a single transmission Access Charge across all PTO territories.

#### d. CRRs Will Not Serve As A Hedge Against Losses

In the June 17, 2002 MD02 Tariff filing, the CAISO proposed that CRRs would serve as a hedge against both congestion and the marginal loss component of LMPs between a sink and a source. Upon further consideration, the CAISO has revised its proposal to provide that CRRs would serve only as a hedge against congestion and not losses. This approach is consistent with the SMD NOPR and similar to the approach used by ISO New England and the New York ISO.[92] Further, the Commission recently has recognized that the ability to hedge losses is not a necessary prerequisite for accepting the use of marginal losses. *Midwestern Independent Transmission System Operator, Inc.*, 102 FERC ¶ 61,196 at P 54 (2003). The CAISO's proposed approach also promotes revenue neutrality, whereas allowing CRRs to serve as a hedge against losses could result in a systematic revenue shortfall in an LMP paradigm that takes marginal losses into account. In that regard, energy settlement revenues would be reduced by the cost of marginal losses that would have to be purchased by the CAISO. Specifically, if CRR holders receive marginal loss revenues (in addition to congestion revenues), then the loss revenues from the energy settlement may not be sufficient to cover their loss revenue entitlement.

[92] See, SMD NOPR at P 244.

### 3. CRR Allocation Issues

#### a. Summary of the CAISO's Proposal

The CAISO recognizes that in the White Paper, the Commission indicated that it would "look to regional state committees to determine how such [CRRs] should be allocated to current customers based on current uses of the grid." White Paper at 5. The CAISO acknowledges that the additional details regarding CRR allocation will be developed in a manner consistent with the White Paper. The proposal described in this section reflects the CAISO's general objectives regarding the allocation of CRRs. The CAISO will finalize the details pertaining to the allocation of CRRs in conjunction with appropriate state entities over the coming months. The CAISO submits that any uncertainty regarding this aspect of the MD02 proposal does not materially affect the general CRR allocation principles enunciated herein, the other elements of the CRR proposal (or the market design in general) and, therefore, should not affect the Commission's decisions with respect to such design elements.

The CAISO proposes to allocate CRR obligations to all loads within the CAISO Control Area, potentially including those loads served under ETCs.[93] Loads such as those of the State Water Project that are not formally served as retail consumers by a LSE will also receive CRRs. *See* Paragraph No. 84 of the amended Comprehensive Market Design Proposal. The underlying principle is that loads within the CAISO Control Area that pay the embedded costs of the transmission grid are entitled to an allocation of CRRs. In general, such CRRs will be allocated to LSEs on behalf of the loads they serve, but the CRRs will "follow the load" if the consumer switches to a different LSE. This makes it unnecessary to create new CRRs when a new LSE enters the market and acquires existing customers of another LSE. Any remaining transmission capacity available for CRRs beyond the allocation to loads will be offered in a CAISO-operated auction, with revenues from the sale of any non-allocated CRRs going to reduce the Transmission Revenue Requirement of the relevant PTO.

The CAISO intends to allocate quantities of CRRs that are adequate to fully protect loads from congestion costs, provided these quantities are simultaneously feasible as determined by the process described below. The CRR study that the CAISO is currently undertaking will provide an early indication of whether it will be feasible to allocate CRRs at this level.

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[93] As discussed supra, allocation of CRRs to ETC loads is one possible way to enable ETC loads to hedge congestion costs, to which they will be exposed under the CAISO's proposal for honoring ETCs. The CAISO will work with the affected parties to determine the most appropriate way to achieve this objective. Of course, if ETC schedules are exempted from congestion charges, as they are today, the loads served by ETCs should not be allocated CRRs and this issue becomes moot.

In the May 1 Filing, the CAISO proposed to allocate CRRs to LSEs "net of local generation." Subsequently, the CAISO recognized that a workable definition of "local generation" would be extremely difficult to implement in a nodal LMP market design and, therefore, decided to drop the netting provision. Further, there was some concern that because hydro-dependent resources have a variable maximum output related to the amount of water in any given year, determining the proper quantities of CRRs for that LSE using a "fixed" amount of local generation would unnecessarily expose the LSE to risk due to the resulting variable amount of CRRs they would receive from year to year. Accordingly, the CAISO's objective is to allocate CRRs in the amount needed to fully hedge gross load against congestion charges. The exact level of CRRs to be allocated will be finalized following completion of the CRR study.

ETC rights holders that convert their rights will be offered a choice of CRR Options or CRR Obligations. The capacity associated with any CRR Options issued will be modeled in a way that essentially sets aside this capacity in the network in order to determine the amount of CRR Obligations that may be released.

Following the allocation of CRRs to converted ETCs and LSEs, the CAISO will run a CRR auction to enable qualified bidders to obtain rights to any transmission capacity that remains after loads and converted ETC holders receive their CRRs. Entities that receive an initial allocation of CRRs will be able to participate in this auction as buyers or sellers[94], and the auction revenues generated by the sale of any allocated CRRs will be paid to the selling entities. CRR auction revenues generated by the sale of any capacity not previously allocated to loads and converted ETC holders will be paid to PTOs to be applied towards their respective Transmission Revenue Requirement. In addition, sponsors of new transmission facilities that elect to fully fund such facilities (*i.e.*, do not propose to include the cost of such facilities in the CAISO's Transmission Access Charge) will also receive CRRs commensurate with the new transmission capacity added to the system.

Based on the design features described above, the CAISO proposes to release CRRs according to the sequence of steps described fully in Paragraph 93 of the amended Design Proposal.

#### b. Determination Of Entities Entitled To Receive CRRs

The underlying principle behind the allocation of CRRs is that all firm native loads within the CAISO Control Area that pay the embedded costs of transmission in California (including, for example, the State Water Project) should

[94] Sellers of CRRs can only participate in the CRR market with a term commensurate with their CRRs. For example, a holder of an annual CRR cannot offer to sell one month of that CRR in a monthly primary auction, but could do so in the secondary market.

be allocated CRRs to the extent they are exposed to congestion charges. In general the LSEs that serve such loads will be the recipients of CRRs on behalf of the loads, subject to the principle that a given LSE's allocation of CRRs will be adjusted when loads switch from one LSE to another.

### 4. CRR Use for Ancillary Services

As is done today, the CAISO will permit a certain amount of Operating Reserves to be provided from outside of the Control Area, via the inter-ties. The CAISO currently requires that no more than fifty percent of its Operating Reserve requirements be procured from resources outside the CAISO Control Area. One important distinction from today is that under MD02, A/S will be afforded a priority equal to that of energy for purposes of securing available transmission capacity over the inter-ties. In other words, A/S capacity and energy will compete to reserve transmission across inter-control area interfaces. If there is congestion on an inter-tie over which A/S is being imported, the supplier of the A/S import will be charged the applicable congestion usage charge.[95]

To enable providers of imported Operating Reserves to hedge congestion cost risks, the CAISO will allow market participants who want to import A/S into the CAISO control area to purchase CRRs through the auction process or the secondary market.

### 5. CRR Terms and Release Quantities

The CAISO proposes to release CRRs on a two-year rolling annual basis and on a short-term monthly basis.[96] *See* Paragraph No. 91 of the amended Comprehensive Market Design Proposal. The transmission network capacity that will be available for annual CRRs for any given operating year will be limited to 75 percent of the capacity of the network but this figure may need to be reduced depending on the outcome of the CRR study. Assuming the 75% target is feasible, then in the first annual CRR auction, all 75 percent would be released for the first year of the CRR term, but only half (37.5%) would be released for the second year. For subsequent annual CRR auctions, the incremental amount of CRRs released for the first year of the CRR term would be the difference between the relevant 75 percent level at that time, and the amount released in the preceding CRR auction for that year. The volume of CRRs released for the following year would be based on the 37.5 percent of the relevant transmission

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95 Congestion charges are not relevant for A/S procured within the CAISO control area because A/S requirements will be defined and met on an internal area basis, not a nodal basis. As described elsewhere, A/S supplies located within each internal area will be able to serve the entire area.

96 In its original MD02 Filing, the CAISO proposed to allocate CRRs for up to three years. However, The CAISO has re-evaluated its policy in recognition of the PTOs' rights to leave the CAISO upon two years' notice. Under these circumstances, the CAISO believes that it is prudent to release multiple one-year CRR's on a two-year rolling period rather than have a CRR product with a three-year term.

capacity. This enables participants to obtain CRRs that are valid for a period of two years following the allocation procedure. The remaining network capacity, will then be available for monthly CRRs and will be based on expected system conditions for the coming month, taking into account seasonal factors and planned outages.

Given the unfamiliarity most parties face in changing from a zonal congestion management system to LMP, some parties have argued that two years is too long a duration for CRRs at this time, and that 75 percent of network capacity is too large an amount to tie up in annual CRRs initially. Other parties point out there are contracts longer than two years that cannot be hedged fully under the CAISO's proposal; so, two years in some cases is too short a duration.[97]

With respect to certain parties' desire for even longer-term CRRs, the CAISO believes that it is prudent to limit CRR availability to the proposed two successive one-year periods, at least initially, until the CAISO and Market Participants gain experience with LMP. The CAISO's proposal will allow market participants that desire longer-term CRRs to obtain one-year CRRs for each year of a two-year period. This would enable them to obtain a longer-term hedge than otherwise would be available with a standard one-year CRR release. With respect to the concerns that 75 percent of network capacity is too large a share for annual CRRs initially, the CAISO proposes to reassess the 75 percent target based on the results of the CRR study and the LMP testing to be conducted prior to start-up of the new market design. The CAISO's proposed CRR release quantities, particularly the distribution between annual and monthly CRRs, necessarily are only a conceptual target at this time, because concrete data are not yet available upon which to base a determination of optimal release quantities. The CAISO's proposal intentionally retains flexibility to modify the proposed CRR product if the need arises based on testing and initial operations under LMP, which is an entirely new market paradigm in California. As the CAISO gains experience from the operation and the monitoring of the CRR market, the release quantities may need to be modified to reduce or eliminate the possibility of market manipulation. Given that the CAISO is completely overhauling its market design, including the design of its CRR products, this is a prudent approach.

Certain Market Participants expressed concerns that they will not receive CRRs that fit their needs which may vary from on-peak to off-peak periods and from season to season. In particular, these parties expressed concern about their exposure, under the CRR Obligations instrument, to congestion costs in the opposite direction of their CRRs during periods when they are scheduling significantly below the quantities of their CRRs (*i.e.*, off-peak). One strategy for mitigating this risk would be to request smaller quantities of CRRs than they

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97 Parties offered the following alternatives: (1) offer only one-year CRRs initially; and (2) offer one, three and five year CRRs initially.

would otherwise be entitled to, but this strategy would expose them to congestion costs during peak periods when their schedules exceed the quantities of their CRRs. The CAISO did not envision providing on-peak and off-peak CRR's in its May 1, 2002 filing. However, to address the concerns expressed about CRRs providing an adequate hedge in the new market paradigm, and the likelihood that only offering a standard "24-by-7" CRR would expose LSEs to unacceptable risks, the CAISO now proposes to release on-peak and off-peak CRRs.

### 6. CRR Secondary Market

The CRR secondary market offers capabilities for CRR holders that do not exist in the CAISO's allocation and auction processes. In particular, the CAISO's processes will not allow CRR holders to unbundle their CRRs to offer them in the auction process. For example, a party holding an annual, peak-period CRR from point A to point B could not offer just the summer months of that CRR in the CAISO's auction.[98] For secondary trading, however, CRRs may be unbundled into any specific hours of the day, days of the week or seasons that parties desire, and network-service CRRs (NS-CRRs) may be unbundled into their separate injection nodes consistent with the distribution factors defining the CRR.

No changes are proposed to the CAISO's current approach for handling trades in the CRR secondary market. Currently, the CAISO does not conduct a secondary market, but does require both parties to any secondary trade of CRRs to register their trades in the CAISO's Secondary Registration System ("SRS"). Thus, the CAISO does not itself intend to facilitate CRR trades other than through its normal auction process.

### 7. Position Limits on CRR Holdings

At this time, the CAISO does not at this time propose imposing position limits on the holding of CRRs. The CAISO will reconsider the possibility of imposing position limits on the amount of CRRs possessed by an entity or its affiliates if there is evidence of gaming or exercise of market power through possession of excessive amounts of CRRs.

### 8. CRRs For Third Party Transmission Expansions

As discussed in Paragraph 96 of the amended Comprehensive Market Design Proposal, when new transmission capacity is added or removed, the CAISO will review the impact of the change on the system network to determine the appropriate amount of new capacity to be released in subsequent CRR allocations and auctions. In that regard, when a new transmission line or an

[98] Of course, a party holding 50 MW of such CRRs could offer a portion of those MW in the CAISO's auction and could unbundle the injection nodes of Network Service CRRs. However, this is the only type of unbundling permitted.

upgrade to an existing line becomes operational, it will alter flows throughout the network and will likely affect the pattern of CRRs that can be released.

Paragraphs 96 and 97 of the amended Comprehensive Market Design Proposal set forth the conditions under which merchant transmission would be granted CRRs. Specifically, if the owner of the new facility or the sponsor of the upgrade will not recover the cost of its investment through the CAISO's transmission Access Charge, the merchant transmission owner will receive CRRs associated with the increased transmission capacity. The CAISO proposes that CRRs be allocated in a manner consistent with the Commission's directive in its March 12, 2003 order on Amendment No. 48 to the CAISO Tariff and the methodology described in the CAISO's filing to comply with the Amendment No. 48 Order.[99] In that regard, in its Order on Amendment No. 48,the Commission stated that "a Project Sponsor should receive FTRs associated with the full amount of capacity added to the system."[100]

Under the CAISO's proposed methodology, a Project Sponsor's share of CRRs is determined by dividing the incremental amount of new capacity realized through the transmission upgrade by the total capacity of the upgraded line, and the PTO's share of such CRRs is determined by subtracting the Project Sponsor's share from one hundred percent (100%). The CAISO's proposal should serve as an incentive for certain parties to build transmission facilities. For example, a merchant generator who creates new or upgrades existing transmission facilities to ensure delivery of its output will be able to preserve the right to congestion revenues even though other SCs' energy may flow over those facilities. The CAISO's proposal is consistent with the policy enunciated in the White Paper. White Paper, Appendix A at 8.

In developing the MD02 proposal, the CAISO anticipated that the award of CRRs to parties financing either a transmission expansion or a transmission upgrade would be subject to a Simultaneous Feasibility Test, designed to ensure that any CRRs awarded in conjunction with the expansion would be simultaneously feasible in combination with all previously awarded CRRs, thereby supporting the CAISO's Revenue Adequacy. The award of CRRs would

[99] As the CAISO explained in its compliance filing in Amendment No. 48, the CAISO did not propose to allocate FTRs to sponsors of transmission upgrades; rather the CAISO proposed to allocate FTR auction, Wheeling, and Congestion revenues. Therefore, the allocation methodology proposed in the compliance filing, while based on the aforementioned principle articulated in the Amendment No. 48 Order, applied to FTR revenues, not to FTRs themselves. Transmittal Letter for Amendment No. 48 Compliance Filing, Docket No. ER03-407-002 (filed Apr. 11, 2003), at 2; *see also* Errata to Amendment No. 48 Compliance Filing, Docket No. ER03-407-003 (filed Apr. 16, 2003) (providing corrected version of allocation methodology). In the present filing, the CAISO has proposed that the Commission-approved methodology be applied to the allocation of CRRs.

[100] *California Independent System Operator Corporation*, 102 FERC ¶ 61,278, at P 21 (2003) ("Amendment No. 48 Order").

provide these beneficiaries with the effective means for capturing and retaining the market value of their investments or to attract investors. An investment opportunity may be attractive based on the beneficiaries' ability to sell the awarded CRRs at market prices to other participants or on the value of the stream of expected congestion revenues.

#### 9. Incorporating New Transmission Capacity into CRR Release

Some parties suggested during the LMP/CRR Working Group process that new transmission capacity should be included in the calculation of CRRs based on the anticipated in-service date of the capacity, rather than waiting until such capacity becomes operational. The CAISO's existing Tariff allows capacity to be offered in auction only after it has demonstrated availability. The CAISO acknowledges that, depending upon what is required for an acceptable demonstration period, this could result in new transmission capacity being reflected in auctions and allocations only in monthly CRR quantities until there is sufficient experience with the new capacity. In light of this, certain parties suggested that new transmission capacity should be included in the calculation of CRRs based on the anticipated in-service date of the capacity, rather than waiting until such capacity becomes operational.

The CAISO is sympathetic to the concerns expressed by these parties, particularly the desire of potential investors in new transmission capacity to obtain CRRs in advance based on the expected in-service date of their projects. Their suggested solution, however, is not problem-free. For example, problems could arise if CRRs are granted for a project that does not come on-line in a timely manner, or when the quantity of CRRs awarded exceeds the capacity of the facility based on actual operational experience. Moreover, the alternative proposal ignores the fact that granting CRRs on a line can have implications on the entire network, and not just the particular line. For these reasons, the CAISO does not support this proposal, but maintains that CRRs should be allocated or offered in auction only after the new capacity has demonstrated availability. Incorporation of the demonstrated new capacity in the monthly allocation/auction process is the most prudent way to accommodate the new capacity in a timely manner.

### D. Ancillary Service Markets

#### 1. Summary Of The CAISO's Proposal

As discussed in greater detail in Section 2.27 of the amended Comprehensive Market Design Proposal, CAISO proposes to incorporate A/S procurement into the Day-Ahead and Hour-Ahead IFM. The CAISO will procure four services: Regulation Up, Regulation Down, Spinning Reserve and Non-spinning Reserve. The CAISO will allow SCs the option of self providing A/S to meet their obligations or relying on the ISO's procurement of A/S.[101] The CAISO may procure only a portion of its expected requirement in the Day Ahead IFM and procure the remainder in the Hour Ahead IFM. However, by the close of the Hour Ahead IFM, the CAISO will have procured its entire expected A/S requirements for that operating hour.

A/S may be provided by Participating Loads that meet CAISO requirements. Current CAISO and WECC standards limit this to provision of Non-spinning Reserve.

The A/S requirements will be determined by the CAISO prior to the IFM optimization, based on the CAISO's load forecast, estimated firm net interchange, and anticipated Real-Time system conditions. Depending on network constraints and congestion, A/S requirements may be determined for major sub-areas of the CAISO control area, which may result in different A/S clearing prices for each sub-area for each service.[102] Although suppliers of A/S will be paid the appropriate area-specific Ancillary Services Marginal Price ("ASMP"), loads will be charged one system price per service. Within some constrained areas of the grid the CAISO may need to limit the amount of A/S procured so that resources within those areas can be utilized for energy to the extent needed. Higher-quality services can substitute for lower-quality services in A/S procurement when such substitution reduces total procurement bid cost. For example spinning reserve service can be procured to meet a portion of the requirement for non-spin.[103]

A/S may be provided via imports up to limits pre-specified by the CAISO. Imported A/S will require transmission allocation in the IFM, which means that A/S capacity and energy will compete for transmission capacity across inter-control area interfaces. If A/S imports contribute to congestion at an inter-tie, the supplier of the A/S import will be charged the applicable congestion usage charge. A scheduled A/S import does not create a counter-flow for an energy export schedule since the A/S import has no associated energy flow schedule.

[101] A resource will be able to both self-provide A/S and offer capacity into the CAISO's A/S markets (*e.g.*, use a portion of its capacity to self-provide A/S and bid for the same service using the remaining portion of its capacity). In addition, for must-offer units, any capacity associated with "over" self-provision will be available for optimization in the energy market. For non-must offer units that over self-provide A/S, the CAISO will offer a "flag" so that the Scheduling Coordinator can indicate what, if any, left over capacity should be optimized in the energy market.

[102] The CAISO's software will have the functionality to identify unloaded capacity as a variable for consideration in nomogram analysis. Nomograms are used to define the relationship between load and generation (and perhaps other parameters, such as voltage and system stability) and will guide local area A/S requirements determinations.

[103] Only the 10-minute portion of Regulation will be eligible to substitute for Spinning Reserve or Non-spinning Reserve.

### 2. A/S Bidding and Pricing Structure

A/S resources will be selected in the IFM using an integrated approach that co-optimizes energy and A/S procurement to minimize total bid costs based on each resource's energy and capacity bids. Resources that do not submit capacity bids for A/S will not be considered for A/S procurement. The ASMP determined in the IFM for each service will implicitly include the opportunity cost associated with providing the A/S instead of being scheduled for energy in the same market, if such opportunity cost exists.[104] If the IFM commits a resource to provide energy or A/S the resource will be eligible for start-up and minimum-load cost compensation.

The CAISO proposes that market participants be able to submit up to four separate capacity bids, one for each type of service.[105] One advantage of allowing a capacity bid is that it enables the supplier to incorporate any additional costs associated with A/S provision into this bid, *i.e.*, costs that are above and beyond those already reflected in the resource's start-up and minimum-load bids. This feature may be important for providers of Regulation Service whose Real-Time dispatch comes from AGC based on physical criteria rather than energy bids. Accordingly, Regulation service providers may not recover their energy bids through Real-Time prices.

Under MD02, the CAISO will not allow SCs to substitute one A/S unit for another once a resource has been selected in the Day-Ahead IFM. However, as is done today, the CAISO will permit Scheduling Coordinators to buy back A/S in the Hour-Ahead market and simultaneously offer A/S from another unit if the unit has been awarded A/S becomes physically incapable of delivering A/S.

### 3. A/S for Contingency Use Only

Today, the CAISO permits providers of A/S to set a "Contingency Only" flag that indicates to the CAISO that the resource should only be called for energy under contingency conditions (*e.g.*, a plant or transmission line outage). This is an important feature to many market participants because it enables them to "protect" energy or use-limited resources.

The CAISO proposes to retain the "Contingency Only" flag under MD02. Thus, A/S providers will have the ability either to opt into the Real-Time imbalance energy dispatch (*i.e.*, do not set the flag) or stay out of the imbalance

[104] The opportunity cost to the marginal resource is determined as the difference between its LMP and its bid at the optimal dispatch point of its energy schedule. The opportunity cost exists only if the available capacity is limited and both the A/S bid and the energy bid of the resource compete for the use of the available capacity.

[105] The CAISO believes that four capacity bids are appropriate. Regulation, Spin and non-Spin impose different operational requirements on a unit and, therefore, should be bid separately. Because Reg-Up and Reg-Down are procured and priced separately, they should be bid on separately.

energy dispatch to be reserved for contingency situations only (*i.e.*, set the contingency only flag). The CAISO supports retention of this feature in order to afford market participants maximum flexible with respect to the scheduling and use of their resources.

### 4. A/S for Exports

The CAISO currently does not support or allow exports of A/S. Under MD02, the CAISO proposes to support A/S exports through the CAISO's current "On-demand Obligation" feature. *See* Paragraph 53 of the amended Comprehensive Market Design Proposal. Under this approach, market participants will be able to export A/S and will be subject to transmission congestion charges. The CAISO believes that this feature of MD02 will facilitate a robust Western market, promote reciprocity and minimize seams issues.

Under the CAISO's proposal, on-demand obligations would be submitted by SCs as part of the scheduling process, and such obligations would be added to the relevant SC's overall Operating Reserve obligation (the applicable SC may self-provide to satisfy its A/S obligations) and to the CAISO's Operating Reserve requirement at the relevant Scheduling Point. On-demand obligations would be met optimally by Operating Reserve imports at the same Scheduling Point and Operating Reserves procured from within the control area. On-demand obligations would compete with energy schedules in the export direction in the forward market and thus may face congestion charges.

### 5. Procurement of A/S in the Hour-Ahead and Requirements For Real-Time A/S Procurement

The CAISO may defer satisfying all of its projected Day-Ahead A/S requirements until the Hour-Ahead market if the CAISO believes that its load forecast (and, thus, it's A/S requirement) is likely to change. This will allow the CAISO to minimize the risk of over-procuring A/S. Deferment of A/S procurement also allows the CAISO to adjust Day-Ahead A/S procurement to account for SC self-provision of A/S in the Hour-Ahead market. Finally, the CAISO may defer procuring A/S if it anticipates that the price of A/S may be lower in the Hour-Ahead market. This is consistent with the CAISO's obligation to procure A/S at least cost. The CAISO will not defer Hour-Ahead A/S procurement to Real-Time unless there are insufficient A/S bids in the Hour-Ahead market.

The CAISO will procure additional operating reserves (Spin and Non-spin) in Real-Time if needed to maintain required reserves when A/S capacity procured or self-provided in the forward markets is dispatched in Real-Time for energy or is unavailable due to outages. Real-Time A/S procurement will be conducted as part of the intra-hour short-term resource commitment procedure every 15 minutes, and will be performed using dynamic co-optimization of energy and A/S. Resources selected in this process will receive notice via the CAISO's Automated Dispatch System. There will not be a market clearing price for Real-Time A/S that are procured, nor will capacity bids be considered. Rather, a resource designated to provide A/S in Real-Time will receive its opportunity cost, determined as the positive difference between the Real-Time clearing price and the resource's energy bid price over the range of capacity selected to provide the additional A/S capacity. If the CAISO commits an off-line resource for Real-Time A/S, that resource will be eligible for recovery of its applicable start-up and minimum load costs.

### E. Adoption Of A Day-Ahead Must-Offer Requirement

To provide adequate safeguards against the exercise of market power through physical withholding, the CAISO proposes that Must Offer Resources will be required to bid or schedule their entire operable capacity into the Day-Ahead and Hour-Ahead IFM to be available for commitment by the CAISO in the Day-Ahead and Hour-Ahead IFM and RUC process, as well as be available for Real-Time dispatch by the CAISO to the full extent of their operable capacity.[106] *See* Paragraph Nos. 1-4 of the amended Comprehensive Market Design Proposal. The CAISO's existing Must Offer Obligation ("MOO") only requires that resources bid their available capacity into the CAISO's Real-Time market. Although the proposed MOO will not require participation in the forward A/S markets, self-scheduling or bidding A/S will satisfy MOO.

The CAISO believes that a Real-Time Must Offer Obligation should be a permanent and fundamental condition for market based rate authority.[107] Fundamentally, if a resource owner has available capacity and can offer that capacity based on an energy and/or A/S bid price of its choosing, there is no legitimate reason for why such capacity should not be offered to the CAISO Real-Time market. Moreover, for units with significant startup times, a Real-Time MOO must be applied through a Day-Ahead unit commitment process (*i.e*. Day Ahead RUC), as is done today through the CAISO's current Must Offer Waiver Process.

The CAISO submits that extending the MOO to the Day-Ahead and Hour-Ahead energy markets is necessary to support the proposed market design proposal and is a reasonable condition of granting generators market-based rate authority. At a minimum, extension of the MOO to the forward energy markets

[106] Resources with legitimate use limitations such as emissions-constrained resources or hydro resources designated as meeting capacity obligations, would be managed in a manner consistent with their limitations.

[107] Today, the Commission-imposed MOO applies to all non-hydro units within California that use the CAISO Controlled Grid or participate in CAISO markets.

should be maintained until such time as a fully effective resource adequacy program has been implemented.[108]

Adoption of a Day-Ahead MOO would provide consumers and state policy makers with increased confidence that California markets will not be subject to rampant market manipulation and physical withholding immediately upon implementation of a new market design. As the Commission is well aware, there is significant skepticism regarding and opposition to implementation of LMP in California. A Day-Ahead MOO could help allay stakeholder and State policy maker concerns that the new market design, including LMP pricing, will be problematic and susceptible to market manipulation.[109] A Day-Ahead MOO

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[108] This constitutes a logically consistent way to implement the MOO in connection with a new market design that features a forward energy market. While the existing MOO is designed to prevent physical withholding by requiring all resources to bid available capacity in Real-Time, the proposed MOO requires resources to make capacity available in the forward market. Thus, the CAISO's proposal not only addresses the withholding problem, but also furthers the CAISO's and Commission's objective of moving commitment and operating decisions into the forward market and out of Real-Time. *See 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 61,361-62 , 61,365 (2000); 93 FERC ¶61,294 at 61,493-96 (2000). In addition, by maximizing the number of resources that are available in the forward market, the CAISO is furthering its objective of ensuring consistency between the forward and Real-Time markets. Absent a requirement of full participation in the forward markets, suppliers may have the incentive to hold out until the Real-Time market in anticipation of higher prices.

[109] Stakeholder concerns about market manipulation and physical withholding are not unfounded. In that regard, there has been evidence of physical withholding of capacity in the CAISO markets. *See Final Report On Price Manipulation In Western Market, Fact Finding Investigation of Potential Manipulation Of Electric And Natural Gas Prices, at VI-54-55,* Docket No. PA02-2 (March 2003) ("Final Report"). Further, in a June 2002 report titled "*Restructured Electricity Markets-California Market Design Enabled Exercise of Market Power"*, the General Accounting Office ("GAO") found "evidence that wholesale electricity suppliers exercised market power by raising prices above competitive levels during the summer of 2000 and at other times during restructuring." GAO Report at 4, 11-17. The GAO Report also acknowledged several studies that concluded that "wholesale suppliers were able to exercise market power by withholding electricity from the market, only making it available at the last minute when buyers were desperate enough to acquire enough electricity and therefore were willing to pay higher prices.[109] *Id* at 4. In that regard, plant unavailability in California was significantly higher during the energy crisis when compared to the number of plants off-line before the crisis. *The California Electricity Crisis: Causes and Policy Options', p. 355, Christopher Weare (2003).* The Commission Staff also found an increased level of unexplained outages at generating plants in 2000. *Staff Report to the Federal Energy Regulatory Commission on Western Markets and Causes of the Summer of 2000 Price Abnormalities,* p. 2-19 (November 1, 2000). The Staff Report did not reach any conclusion why plants were out of service. However, a March 21, 2001 study prepared by the CAISO's Department of Market Analysis entitled "*Empirical Evidence of Strategic Bidding in the California Real Time Market"* found that suppliers engaged in physical and economic withholding to influence market prices in 2000.

Further, two of the primary suppliers of electricity to the California market –Reliant and Williams -- have faced allegations that they physically withheld power with the intent to drive up electricity prices in the State. *See Fact Finding Investigation into Possible Manipulation of Electric* would bring necessary stability to the market as the CAISO transitions to LMP and would help to restore the State's confidence in markets.

The CAISO recognizes that the Commission might have concerns about imposing even an interim Day-Ahead MOO absent the existence of a formal resource adequacy requirement. In that regard, a formal resource adequacy plan might provide capacity or availability payments to resources that are identified as fulfilling the resource adequacy requirement; whereas, the CAISO's Must Offer proposal does not entail such payments. However, there are several reasons why lack of an existing formal resource adequacy program should not preclude approval of the proposed interim Day-Ahead MOO. In that regard, the overwhelming majority of load in California is covered by long- and short- term contracts, and suppliers are receiving capacity payments not only through such contracts, but also through a number of other mechanisms. These mechanisms, when considered together, constitute an adequate and effective substitute for a formal resource adequacy program pending the State's establishment of such a program.

First, the power supply contracts entered into by the State of California – which provide capacity payments to suppliers – account for approximately 70 percent of the IOUs' net short load requirements during peak periods. Given that most load in California is already "locked-up" by long-term and short-term bilateral contracts (as well as by utility retained generation) and CAISO market purchases only constitute a *de minimus* portion of total market activity (in most months only one to two percent during the past year), there is no merit to the argument that suppliers need a formal resource adequacy mechanism in place before an interim Day-Ahead MOO can be imposed.

Second, in November 2002, the CPUC directed the IOUs to resume procurement beginning January 1, 2003, approved IOU procurement plans for 2003 and established a framework for cost recovery of diverse electricity products including forward contracts for energy and capacity. The IOUs have in fact been entering into short-term contracts with suppliers. These contracts should provide an opportunity for suppliers to recover fixed costs.

Third, the CPUC has ongoing a long-term procurement proceeding in Docket No. R01-10-024 which it will determine the standards for long-term procurement for the three IOUs. In April 2003, the three utilities submitted their long-term procurement plans which will be the subject of a CPUC hearing in July, 2003. Among the issues that the utilities have addressed in their long-term procurement plans, is an adequate planning reserve level. Thus, progress is

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*and Natural Gas Prices*, 102 FERC ¶ 61,108 (2003); *AES Southland Inc. and Williams Energy Marketing and Trading* Company, 94 FERC ¶ 61,248 (2001). Given the evidence of physical withholding in the California market, it is appropriate that the Commission impose a Day-Ahead MOO at this time.

being made toward the development of a long-term resource adequacy plan. In the White Paper, the Commission has deferred to the states on the issue of resource adequacy. White Paper at 5. In particular, the Commission stated that the independent transmission provider cannot implement a resource adequacy plan unless the state does not act or the state directs the transmission provider to develop such a plan. *Id.* Because the Commission has deferred resource adequacy to the states, the Commission cannot use the CAISO's lack of a formal resource adequacy plan as a basis for rejecting the proposed interim Day-Ahead MOO, especially given the fact that the State is currently in the process of developing a formal resource adequacy plan.

Fourth, the CAISO already provides – and is proposing to provide in this filing – capacity payments to suppliers via a number of mechanisms. For example, in 2002, the CAISO paid out approximately $260 million dollars annually in capacity payments to RMR units in 2002 and approximately $85 million in A/S capacity payments.. Finally, the CAISO is proposing, as part of the RUC procedure to make an availability payment to suppliers per MW of capacity that is committed in RUC, but not awarded A/S or dispatched or scheduled for energy.[110]

### F. Residual Unit Commitment

#### 1. It Is Appropriate And Necessary For The CAISO To Have A Reliability Unit Commitment Mechanism

##### a. Introduction

Currently, the CAISO relies on the existing MOO and the Must Offer "waiver" procedure to commit resources when it believes that scheduled resources will not be adequate to meet forecasted demand. Because the CAISO does not consider economics when deciding which units it should grant waivers to or revoke waivers from, it has been difficult for the CAISO to make rational and efficient decisions about which units should be required to run at minimum load under the MOO when some, but not all, of the units seeking a waiver need to be committed to maintain grid reliability. The current process of waiver denials suffers from the following drawbacks: (1) it does not necessarily produce the optimal or most efficient solution to waiver denial because it essentially implements a first-come, first-served policy in issuing waiver denials instead of a sound optimization algorithm such as the unit commitment algorithms used by

[110] The CAISO's Must Offer proposal can be readily distinguished from the recent proposal by the Midwest ISO to apply penalties for physical withholding in its Day-Ahead market. In that regard, in *Midwest Independent System Operator, Inc.*, 102 FERC ¶ 61,280 at P 96 (2003), the Commission rejected that proposal as constituting a "must offer" obligation for capacity resources." As discussed *infra* in the RUC discussion, the CAISO's Must Offer proposal does not suffer the same infirmity because the CAISO's Must Offer/RUC proposal provides an availability payment for capacity resources. Further, the Midwest ISO, unlike the CAISO, has not been plagued by physical withholding, gaming and market manipulation.

the eastern independent system operators; (2) it does not optimally consider the physical constraints of resources such as ramping and minimum up and down times; (3) it does not fully consider network constraints; (4) waiver decisions are based on only the peak hour condition instead of considering conditions for an entire 24 hours; and (5) it does not provide a means for the ISO to procure energy from intertie suppliers – energy that is vital to meet peak loads – in advance of the Real-Time market.

In order to implement a rational unit commitment procedure in connection with the MOO and promote reliable operation of the CAISO-controlled transmission grid, in its May, 2001 MD02 Filing, the CAISO proposed an interim RUC mechanism. The interim RUC mechanism was based on a security constrained unit commitment process that would allow the CAISO to commit additional resources needed to meet the CAISO's forecast of the next day's Load in cases where the market-scheduled resources are deemed inadequate. Although the Commission rejected the CAISO's interim RUC proposal in its July 17 Order, in its October 11 Rehearing Order, the Commission "encourage[d] the CAISO, with input from stakeholders, to develop a long-term residual unit commitment proposal." October 11 Order at P 73.

Subsequent to the October 11 Order, the CAISO has fully vetted the issue of the appropriate design of a RUC mechanism with stakeholders. There are strongly divergent views regarding the proper design of any CAISO unit commitment mechanism. The CAISO has carefully evaluated the positions of stakeholders and revised its original RUC proposal to address certain of the concerns. One significant modification is inclusion a bid-based availability payment (subject to a $100/MW cap) to suppliers. To ensure the proper incentives and limit physical and economic withholding in the Day-Ahead market, the CAISO will rescind such availability payment if the RUC capacity is dispatched for Energy or awarded A/S capacity. In addition, the CAISO now proposes to accommodate bid-based (as well as cost-based) start up and minimum load bids. Finally, in determining the capacity procurement target for RUC, the CAISO will now consider a forecast of expected incremental Hour-Ahead schedule changes. This recognizes that LSEs regularly procure power supply in the Hour-Ahead to meet Real-Time load. The CAISO believes that the revised RUC proposal meets the CAISO's reliability needs, while accommodating suppliers' requests for a market-based mechanisms and consumers' needs for adequate protections against gaming and the exercise of market power. Accordingly, the Commission should approve the CAISO's revised RUC proposal as a necessary reliability tool.

### b. Summary of the RUC Proposal

The CAISO will perform a Day-Ahead and Hour-Ahead RUC process immediately after the Day-Ahead or Hour-Ahead IFM has run and has established feasible final Day-Ahead or Hour-Ahead schedules. Both the Day-Ahead and the Hour-Ahead IFM clear based only on the bids and self-schedules that SCs have submitted, without regard to the CAISO's load forecast. In the event that these markets close significantly below the CAISO's load forecast and do not commit adequate resources to meet that forecast, the RUC provides a reliability backstop for the CAISO to commit additional supply resources if needed to meet the system load forecast and reserve requirements (in compliance with NERC and WECC reliability criteria, as well as local reliability needs).

The CAISO needs both a Day-Ahead and an Hour-Ahead RUC because different resources will be issued commitment instructions in each depending on their start-up times. For example, the Day-Ahead RUC will issue commitment notices only to resources requiring day-ahead or longer notice; whereas, the Hour-Ahead RUC will issue commitment notices to resources requiring only a few hours or less notice. In order to account realistically for resource operating constraints in the commitment process the SCUC used in the Day-Ahead RUC (Hour-Ahead RUC) will utilize a multi-day (multi-hour) time horizon. All resources subject to Must Offer Obligations will be required to participate in the RUC procedure.[111]

The capacity procurement target for the Day-Ahead RUC will be the next day's hourly load forecast plus reserve requirements, minus: (1) the final Day-Ahead schedule of energy plus A/S capacity; (2) a forecast of expected incremental Hour-Ahead schedule changes; (3) a forecast of additional supplemental energy bids expected on the operating day. The CAISO will refine this estimation procedure to minimize over- and under-procurement. Also, to the extent that metered subsystems ("MSS") within the CAISO Control Area under-schedule in the Day-Ahead market, but have designated adequate resources under their control to meet their own load and reserve needs, the RUC will not procure capacity to cover their share of the next day's forecast, nor will the CAISO allocate a share of RUC commitment costs to these entities.

Although RUC will procure a combination of energy and unloaded capacity (including demand response) to meet 100 percent of the capacity procurement target (*i.e.*, hourly load forecast plus reserve requirements), the energy procurement (from System Resources and the minimum load of RUC-committed resources) will be limited to a maximum of 95 percent of the CAISO's next day hourly demand forecast. The remaining five percent or more will be covered by the unloaded capacity of resources that are scheduled for energy in the Day-Ahead IFM (excluding any capacity scheduled to provide A/S), plus the unloaded capacity of any additional units committed by the RUC process. This five percent margin is intended to allow for load forecast error and to minimize the risk of over-procurement of energy by the RUC. In the event of a conflict between the

[111] Must Offer resources that have verifiable use limitations will not be expected to perform beyond their use limitations, except possibly when emergency conditions make it necessary for the CAISO to call upon them. Therefore, such resources will be considered in the RUC process only as their use limitations allow.

objectives of 100 percent capacity coverage and no more than 95 percent energy coverage, the 100 percent capacity objective takes precedence.

The RUC process will procure minimum load energy and unloaded capacity from internal resources. The RUC process will procure only energy from import suppliers, provided adequate transmission capacity is available on the inter-ties to accommodate this energy after the running of the IFM.[112] Minimum load energy from internal resources and energy procured from inter-ties in the Day Ahead RUC will have scheduling priority over incremental Hour-Ahead energy schedules in the Hour Ahead IFM.

The unloaded capacity committed in RUC may be scheduled for energy or A/S capacity in the Hour Ahead IFM or dispatched in Real-Time based on the resource's submitted energy bids. The incremental energy bid curves associated with such capacity will be submitted to the Hour-Ahead IFM, and any additional energy not cleared against load bids in the Hour-Ahead IFM will be available for real-time dispatch. The incremental energy bids associated with capacity selected in RUC cannot be increased in price once they are selected, but may be decreased prior to Hour-Ahead or Real-Time if the resource wishes to increase its probability of dispatch.

Any energy procured in the Day-Ahead RUC, *i.e.*, the minimum load energy of internal resources committed by RUC, as well as energy procured from import suppliers, will be submitted to the Hour-Ahead market as a price taker (*i.e.*, a self schedule) and, if cleared against load bids, will earn the appropriate locational market clearing price. Any of this energy not cleared in the Hour-Ahead market, as well as any additional energy procured in the Hour-Ahead RUC process, will be submitted to the Real-Time market as a price taker and again may earn market clearing prices. Such resources will receive additional payment through the RUC uplift charge in the event that their revenues from market clearing prices do not cover their energy bid prices.

Resources that did not participate in the Day-Ahead IFM will not be eligible to participate in Day Ahead RUC. This exclusion is necessary to prevent resources from being withheld from the Day-Ahead IFM to participate exclusively

[112] The CAISO's proposal to procure energy from imports, not capacity, is intended to conform better with the scheduling practices in the WECC. In particular, suppliers importing Energy need to line-up transmission capacity outside of California in the Day-Ahead time frame. In the WECC region, most units are committed in advance of the next operating day. The CAISO's proposal to acquire import supply needed to meet unscheduled but forecasted Demand in the Day-Ahead time frame is consistent with this approach. The CAISO is dependent on imports, and the CAISO's proposal facilitates import participation by accommodating in a manner that is consistent with general practices in the West. Finally, the CAISO is concerned that if import suppliers only had a commitment from the CAISO for capacity, that might not be sufficient incentive for them to acquire the necessary transmission capacity (or might otherwise result in an inefficient use of transmission capacity).

in the RUC process. However, they can still participate in Hour-Ahead IFM and Hour-Ahead RUC.

Because the SCUC software will not incorporate the full network model until Phase III is implemented, SCUC will consider only the current Inter-Zonal constraints in Phase II. When the full network model is implemented, SCUC will consider all network constraints. For the foreseeable future, local reliability needs that are met today using RMR resources will continue to be met by RMR resources. However, during Phase II, in areas where RMR resources either have not been designated or are not available, the CAISO may manually commit units through the RUC process based on off-line power flow analysis to address local reliability needs as well as system needs.

#### c. The Proposed RUC Mechanism Is Just and Reasonable

The CAISO's RUC proposal is designed to achieve the following objectives: (1) ensure that sufficient generating capacity will be on-line and available for Real-Time to meet CAISO-forecasted load; (2) provide a reasonable bid-based payment mechanism for resource capacity that is committed in RUC but ultimately not dispatched or awarded A/S, and (3) provide a way for the CAISO to procure needed supplies from imports on a day-ahead basis to supplement in-state supplies, thereby promoting increased reliability and potentially reducing overall RUC procurement costs; and (4) ensure that units will be committed in an optimal and efficient manner. The CAISO believes that its RUC proposal provides a necessary, effective and reasonable reliability tool that can be modified over time with experience.

The CAISO stresses that the existing Must Offer Obligation must be continued in order for RUC – or any reliability commitment process – to be effective. RUC is a unit commitment process designed to enable the CAISO to meet forecasted load by utilizing generating capacity that is required to make itself available to such unit commitment process. By itself, RUC contains no provision to compel supply resources either to participate or make themselves available to the California market. Therefore, to be effective, RUC must be anchored by some mandatory participation requirement for Generators, such as the Must Offer Obligation.

In its July 17 Order, the Commission stated that the CAISO does not need RUC because the Commission has approved the Must-Offer waiver process.[113] The CAISO's proposed RUC mechanism improves the current Must Offer waiver process by considering economics, as well as unit and grid constraints and allowing the CAISO to secure import supplies which California depends on in advance of Real-Time. Thus, RUC is most properly thought of as an

[113] July 17 Order at P 65.

enhancement to the current Must Offer Waiver procedure that will provide a more orderly, transparent, optimal and efficient implementation of the MOO with respect to long-start-time units and will allow the CAISO to procure needed energy from the interties.[114] The RUC process takes advantage of the MOO and enhances its use in ensuring reliability by expanding the available energy resources that can be committed (*i.e.*, intertie supplies). RUC makes the most efficient use of available resources, while ensuring that reliability requirements are met to the maximum extent possible. The CAISO's revised RUC procedure is an integral element of the MD02 comprehensive market design, is fully consistent with the implementation of LMP by other independent system operators and is an absolute necessity for the CAISO to perform its core, NERC-mandated function of reliable grid operation.[115]

The RUC procedure is consistent with the Commission's proposal in the SMD NOPR that system operators have a mechanism to commit additional units when Day-Ahead schedules are less than forecasted load in order to ensure that load can be met reliably in Real-Time. SMD NOPR at P 298. Further, the RUC proposal is comparable to the unit commitment processes employed in markets operated by the eastern independent system operators. In that regard, every other independent system operator in operation has a day-ahead unit commitment process designed to commit sufficient units to meet the independent system operator's forecasted Load and minimize total costs. *See New England Power Pool*, 88 FERC ¶ 61,147 at 61,491 (1999) (independent system operator commits sufficient reserves to ensure that it has adequate supply committed to meet forecasted Load); *Central Hudson Gas & Electric Corporation, et al.,* 86

[114] In a May 15, 2002 Order, the Commission ordered the CAISO not to use economics when issuing or revoking Must Offer waivers finding: "[t]he exemption procedure should not be used to minimize costs to the detriment of reliability. Therefore, we reject the ISO's propos[ed] criteria to grant exemptions to minimize the start-up and minimum load costs necessary to meet the ISO's forecasted demand." *California Independent System Operator Corporation,* 99 FERC ¶ 61,158 (2002). In its October 11 MD02 Rehearing Order, the Commission clarified that "once reliability has been ensured, it would be reasonable for the CAISO to use economic considerations in deciding which units will be granted must-offer waivers (*i.e.*, granting waivers to the highest cost units). Accordingly, the Commission found that "if the CAISO wishes to propose economic considerations as a secondary criteria to reliability, it may do so in a section 205 filing to amend its tariff." October 11 Order at P 72. The CAISO's RUC proposal is responsive to the Commission's invitation to incorporate economics into a unit commitment process.

[115] Certain considerations led to the CAISO'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 the system operator determines that the resources scheduled day ahead will not be sufficient to meet the next day's load and reserve requirements.

FERC ¶ 61,062 at 61,222(1999) (NYISO commits sufficient capacity to meet the load forecast and provide ancillary services); *see also* PJM West Reliability Assurance Agreement, Article 8. Thus, in proposing RUC, the CAISO is not seeking any authority that the Commission has not already approved for other independent system operators. Because RUC performs the same function as the unit commitment procedures in PJM, NYISO and ISO-NE, there is no valid reason why the CAISO should not have RUC.[116]

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### 2. RUC Results Will Not Be Rolled into the Day-Ahead or Hour-Ahead Markets

The CAISO proposes to allow the Day-Ahead market to reflect the bids, offers and schedules submitted by Market Participants. If those bids, offers and schedules fail to reflect forecast operating conditions, the CAISO will make its RUC commitment decisions after the completion of the Day-Ahead market and will carry over any minimum load energy resulting from RUC to a subsequent market (*i.e.*, either to be scheduled by the SC against load in the Hour Ahead market or to be viewed by the CAISO as a pre-dispatch of Real Time Energy). This is similar to PJM where minimum load energy committed in PJM's unit commitment procedure is viewed as a pre-dispatch of Real-Time energy.

In the IFM Working Group, some parties raised the issue whether the cost effects of the CAISO's RUC decisions should be included in the Day-Ahead market. Participants suggested two variations of this concept. The first variation entails running RUC after the Day-Ahead market as proposed in MD02, but then incorporating the minimum load Energy associated with RUC-committed units into the final Day Ahead Schedule. The NYISO follows this approach. The second variation would be to incorporate the RUC procedure into a complete re-run of the Day-Ahead market by having the CAISO bid load in an amount equal

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116 A few parties have argued that the CAISO should rely on Replacement Reserves (as already provided in the CAISO Tariff) rather than RUC. The Replacement reserve, in its current form, is not an adequate substitute for unit commitment because, other than No-Pay, there is no explicit obligation to provide the service. A supplier has the ability to buy back the service in the Hour-Ahead market, thereby creating a reliability issue for the CAISO if the CAISO is relying on an actual unit commitment from the Replacement Reserve. Further, committing units from the Replacement Reserve can have a response time of up to 59 minutes. This reduces the effectiveness of such reserves. Moreover, the CAISO's existing Replacement Reserve does not provide a means to account for locational needs. On the other hand, RUC will allow the CAISO to commit units in specific locations where supply is needed. In addition, under the Replacement Reserve, the CAISO's capacity procurement target is generally based on historical pattern not forecasted load. This makes RUC a more effective tool than Replacement Reserve. In any event, compared to the CAISO's original RUC proposal, the revised RUC proposal contains more market-based elements that are specifically designed to make it more akin to a replacement reserve-type mechanism (*e.g.*, a bid-based availability payment of up to $100/MW which, similar to the existing Replacement Reserve, is rescinded if capacity is dispatched). The existing Replacement Reserve will be eliminated under the new market design.

to the shortfall between the CAISO's load forecast and the final Day Ahead schedule that resulted from Market Participants' bids and schedules.

With respect to the latter proposal, the CAISO believes that it is wholly inappropriate to have the CAISO bid load into a re-run of the Day-Ahead market. The Day-Ahead market outcome should reflect the bids and schedules submitted by Market Participants. If the CAISO were to bid load into this market, it would defeat the ability of Market Participants to limit their purchases in Day-Ahead and force them to purchase Day-Ahead energy up to whatever amount the CAISO's purchasing procedures dictate. Moreover, it would mean that CAISO energy purchasing procedures – rather than participants' economic decisions – become the ultimate determinant of Day-Ahead prices. The CAISO does not consider this to be a viable proposal, so long as the CAISO has an effective RUC procedure that can be run subsequent to the Day-Ahead market.[117]

With respect to the two options for treating the minimum-load energy of RUC-committed resources, the amended Comprehensive Market Design proposal incorporates the same principles employed by PJM. There are reasonable arguments for both approaches. The CAISO prefers the PJM approach because it completely insulates Day-Ahead market prices from any impacts of CAISO RUC decisions. Alternatively, the NYISO approach is based on the logic that final Day-Ahead schedules should include the full complement of resources that are committed for the next day.

The CAISO proposes to utilize the PJM approach. The costs of additional units committed in the RUC process will not be reflected in the Day-Ahead market prices. Rather, RUC commitment costs will be allocated to those Market Participants who failed to fully schedule load in the Day-Ahead market. Allocating RUC commitment costs to market participants who fail to fully schedule load in the Day-Ahead market should appropriately encourage them to do so. To the extent units committed in the Day-Ahead RUC have higher cost energy bids, which one would expect because this capacity was not awarded energy in the Day-Ahead IFM, such higher bids will ultimately be reflected in the Hour-Ahead and Real-Time LMPs, thereby providing further incentive for LSEs to fully schedule load in the Day-Ahead IFM.

### 3. Optimization Objective of RUC

A potential issue associated with any reliability commitment procedure is what the proper objective function of such process should be. Under the RUC process, the goal will be to ensure that enough resources are committed and will

[117] The RUC process is essentially a reliability tool, not a market enhancement process. Consequently, the CAISO desires to allow the market process to take place first and, then, should that process fail to satisfy the CAISO's perceived capacity needs (*i.e.*, fall short of the CAISO's Day Ahead load forecast), the CAISO would commit the necessary generating capacity strictly for reliability purposes.

be on-line (and available) to meet the next day's forecast load (at the least cost). RUC will optimize its selection of resources by minimizing the total bid cost of procuring the resources, including the bid-based availability payment, and dispatching such resources for Real-Time energy to fully meet the Real-Time load forecast. *See* Paragraph 105 of the amended Comprehensive Market Design Proposal. The three-part bids submitted in the Day-Ahead IFM will be used in this RUC process, including each resource's start-up and minimum load bids and its incremental energy bid curve as submitted in the IFM. Technical constraints like minimum load energy and minimum run time will be the actual physical constraints of the resource, not market-based bid constraints. Import bids may not be resource specific and, therefore, may not have cost-based start-up and minimum load bids. The IFM and RUC optimization must consider only the energy bids submitted by these suppliers. Similarly, RUC will not consider start-up and minimum load bids for resources scheduled in the Day Ahead IFM that have additional uncommitted capacity, because these resources were already committed in the Day-Ahead IFM. A commitment based on the minimization of a combination of start-up, minimum load, availability bids and expected energy costs is appropriate given that California is heavily dependent on imports, and the CAISO will be procuring Energy from imports in the RUC process, not capacity.

#### 4. Start-up and Minimum Load Cost Compensation

As discussed in Paragraph 106 of the amended Comprehensive Market Design Proposal, resources committed by the CAISO in the Day Ahead RUC will be eligible for recovery of start-up and minimum load costs, net of market profits during the unit's commitment period. Market profits for the purpose of this start-up and minimum load cost recovery provision include profits from energy payments, A/S capacity payments and the RUC availability payment. Resources that self schedule energy or self provide A/S, after having been committed in RUC, will be viewed as self-committed and will not be compensated by the CAISO for start up and minimum load costs. Further, a resource eligible for start-up/minimum load cost recovery in the Day-Ahead RUC may lose its eligibility during all or part of its commitment period if it engages in uninstructed deviations (beyond a tolerance band)[118]in the Real-Time market.

Suppliers may select one of two options regarding the start-up and minimum load components of a bid—a cost-based option and a market-based option. This approach will provide suppliers with bidding flexibility, while still providing adequate protections against market power. Under the cost-based option, start-up costs would be based on the lower of a supplier's bid or cost-based start-up data provided by the supplier, a proxy figure for natural gas and an electricity price index for start-up auxiliary energy consumption. Minimum

[118] The tolerance bands used for this purpose will be the same as those being established in Phase 1B for assessing uninstructed deviation penalties.

Load costs would be based on the lower of a supplier's bid or cost-based data provided by the supplier, a payment of $6 per MWh of minimum load for presumed O&M costs and a proxy figure for natural gas costs.[119]

Under the market-based option, the start-up and minimum load cost components of the bid are market-based bids that remain fixed for a six month period once they are submitted. Such bids will always be used as the resource's start-up and minimum load cost bids in all markets in which the resource participates during that six month period. In other words, once the resource submits its bids, the resource will not have the flexibility to submit a different bid value in any CAISO market. This is in contrast to the cost-based approach under which a bidder may submit any bid value from zero up to its cost-based start-up and minimum load values.

The CAISO's approach for market-based bids – which is employed by PJM[120] -- is necessary to prevent economic withholding in the bidding of Start-up and Minimum Load costs. Specifically, this approach would prevent resource owners from submitting excessive Start-up and Minimum Load bids when system conditions are sufficiently tight so that the unit owner is virtually assured of being committed in the CAISO RUC procedures.[121] The CAISO recognizes that the NYISO and ISO- NE allow resources to submit daily start-up and minimum load (NYISO) or no-load (ISO- NE), but subject these bids to AMP mechanisms. The CAISO believes that allowing daily bidding flexibility for what should be cost-based uplift parameters is unnecessary, and developing AMP procedures to address market power concerns would be excessively complicated and unlikely to provide sufficient market power mitigation. The six-month bid based election option is acceptable for PJM, and it should be equally acceptable for the CAISO. The CAISO also notes that the SMD NOPR contemplates that bid caps and/or bid-in operating criteria should apply to start-up and minimum load bids in order to mitigate the exercise of market power. SMD NOPR at P 425. The

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119 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." *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 62,563 (2001).

120 *See* http://www.pjm.com/documents/downloads/agreements/oa.pdf (Section 1 – 1.9.7 (b)).

121 The Commission has recognized that suppliers can exercise market power by attempting to inflate start-up and minimum load bids. However, with a six-month "lock-in" period, a supplier that raises its start-up and minimum load bids to capitalize on one set of system conditions would be forced to use the same high bid throughout the six-month period even if less favorable system wide conditions were to prevail in the future. Because high bids under such conditions could cause the CAISO not to dispatch the unit, the supplier could sacrifice profits in the larger energy market. Thus, the six-month "lock-in" makes the submission of inflated bids less likely. *See Atlantic City Electric Company, et al.*, 86 FERC ¶61,248(1999).

Commission recognized that several approaches can be used, including the PJM method of allowing units to change their start-up and minimum load bids only once every six months. *Id.* at P 426. In particular, the Commission stated that "PJM's approach to permit changes to these parameters once every six months may be a simpler alternative that does not restrict competitive generator behavior". *Id.* Consistent with its conclusions in PJM and the SMD NOPR, the Commission should approve the CAISO's proposal with respect to market-based start-up and minimum load bids.

The CAISO's payment methodology for Start-up and Minimum Load costs reflects the fact that the RUC procedure is a reliability tool, not a market enhancement. The RUC payment structure is designed to cover the costs associated with a particular commitment decision, if that decision is made as a result of the CAISO's explicit request. This is appropriate because a resource that is committed by the CAISO is one whose owner has decided not to operate it on a given day presumably because of perceived lack of opportunity to make a profit. If the CAISO wishes to supersede such owner's decision and commit the resource, the CAISO would be responsible to ensure that the resource owner does not suffer a financial loss as a result.

Some parties have argued 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 proposed in the amended Comprehensive Market Design Proposal. 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, "Generators who are dissatisfied with this finding regarding cost recovery of only minimum load costs may propose cost-based rates for their generating units."[122] Further, if suppliers object to the cost-based option, they are free to accept the market-based option and submit bids that reflect their actual start-up and minimum load costs. Under these circumstances, there is no need for the Commission to approve a cost-based option that is based on actual costs.[123]

Several suppliers have objected to the CAISO's proposal to provide recovery of start-up and Minimum Load costs, net of market profits during the next 24-hour operating day. The Commission has approved a "net-of-market"

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[122] *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services into Market Operated by the California Independent System Operator Corporation and the California Power Exchange*, 99 FERC ¶ 61,159 at 61,641 (2002).

[123] The Commission has approved cost-based pricing for start-up and minimum load costs in connection with the MOO. *California Independent System Operator Corporation,* 97 FERC ¶ 61,293 (2001). There is no is no reason why the pricing of start-up and minimum load costs should be any different under MD02.

approach for PJM, NYISO and ISO New England.[124] It is axiomatic that an agency must conform to its prior practice and decisions or explain the reason for its departure from such precedent.[125] The Commission must conform to this mandate. Specifically, consistent with its decisions in PJM, NYISO and ISO New England, the Commission must permit the CAISO to "net" start-up and minimum load costs in the RUC process.

Further, the suppliers' position contemplates that, having been paid Minimum Load and start-up costs through RUC, they can then freely participate in bilateral agreements and CAISO markets, retaining all of the profits by selling the Energy derived from 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.

#### 5. RUC Cost allocation

The CAISO will apply generally accepted cost causation principles in allocating RUC costs. Costs associated with the RUC process will be borne first by SCs whose metered load is not fully scheduled in the Day-Ahead market (excluding Metered Subsystem load that is covered by its own resources and, therefore, does not cause any RUC procurement). *See* Paragraph 111 of the amended Comprehensive Market Design Proposal. Allocating the costs to these under-scheduled loads will provide the proper incentives to encourage LSEs to schedule load fully in the Day-Ahead market. The CAISO will calculate a per MWh RUC charge by dividing total RUC procurement costs by the amount of RUC capacity or energy procured, and will allocate this per MWh charge to each MWh of metered load in excess of final Day Ahead schedules. These charges will be in addition to the cost of energy to serve such load in the Hour Ahead or Real-Time markets. Any excess of RUC costs not recovered in this manner (*i.e.*, if the total MWh of under-scheduled load is less than the total MWh of RUC procurement) will be allocated to all metered demand plus exports. Similarly, the costs associated with Hour-Ahead RUC will be allocated first to metered load in excess of final Hour-Ahead schedules.

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124 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.*

125 *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).

If the CAISO commits units because the CAISO's load forecast is too high, the CAISO proposes that such costs – which are not the direct result of any action or inaction by any Market Participant – should be allocated to all market participants the way other general CAISO costs are allocated, *i.e.*, based on the Market Participant's metered Demand, plus exports to total CAISO Demand plus export. While the CAISO desires to minimize such costs, it is appropriate to allocate them in proportion to each Scheduling Coordinator's overall footprint in the CAISO's markets at the time they were occurred.

### 6. RUC Availability Payment

The CAISO proposes that unloaded capacity be paid a per-MW availability payment for each MW of RUC-procured capacity that is not awarded A/S or dispatched for energy in the Hour-Ahead or Real-Time markets. *See* Paragraph 107 of the amended Comprehensive Market Design Proposal. Resources may submit a bid for RUC availability as a component of their IFM bids, up to a cap of $100 per MW per hour. The availability payment will be rescinded for each MW of RUC capacity that is scheduled or dispatched for energy or awarded A/S capacity in a subsequent market. The resource's entire availability payment for a given hour will be rescinded if the resource engages in uninstructed deviations beyond the CAISO's allowable tolerance band or is not available to respond to a CAISO dispatch instruction. The availability payment will be paid as-bid to resources selected in RUC.

The circumstances under which the availability payment will be rescinded are consistent with the treatment of the capacity payment under the CAISO's existing Replacement Reserve mechanism. Rescinding the availability payment for units that are dispatched removes the incentive for suppliers to submit unreasonably high bids in the Day-Ahead market (so that their bids will not be accepted) or bypassing the Day-Ahead market to receive a RUC availability payment. That problem plagued the CAISO's Replacement Reserve until the Commission approved Tariff revisions rescinding such payment upon dispatch. In that regard, in its November 1, 2000 order in Docket No. EL00-95, the Commission ruled that suppliers could receive either a capacity payment or any energy payment but not both. *See San Diego Gas and Electric Company v. Sellers of Energy and Ancillary Services into Market Operated By the California Independent System Operator and the California Power Exchange*, 93 FERC ¶61,121 at 61,368, n.85 (2000), *order on reh'g*, 93 FERC ¶61,294 at 61,995 (2000). The Commission approved this approach in order to remove the financial incentive for suppliers to favor the Real-Time. 93 FERC at 61,362. Similarly, suppliers should receive only a RUC availability payment or an energy payment in order to eliminate the incentive to avoid the Day-Ahead market by bidding excessively high.[126]

The capacity payment will be paid on an as-bid basis, not on a MCP basis. This payment methodology reflects the fact that the RUC procedure is designed to be a reliability tool, not a market enhancement. As-bid payment, in connection with market-based capacity bids, will adequately compensate RUC suppliers for any perceived costs associated with the CAISO not fully dispatching a unit's RUC capacity. It should be noted, however, that the CAISO does not prohibit energy from capacity committed in the Day-Ahead RUC from being sold by the unit owner via any bilateral transaction in the Hour-Ahead market, including sales to other Control Areas. Therefore, there are no opportunity costs associated with being designated to provide RUC capacity because the capacity can be marketed elsewhere.

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[126] The CAISO's original RMR contracts created a similar perverse bidding incentive and were eventually reformed to correct this deficiency. Specifically, in 1998, the CAISO implemented the so-called "A" form of RMR contract which paid a portion of a unit's fixed costs, in addition to paying the resource's variable costs, whenever the unit was called on to provide service under the RMR contract. As a result, generators with "A" contracts began withholding bids or bidding the extra fixed cost premium into the PX Day Ahead market to ensure receiving the additional fixed cost compensation that they were guaranteed under the RMR contract. In other words, the variable cost adder provided under the RMR "A" contract represented an opportunity cost that unit owners would be foolish to relinquish by bidding below this premium in the energy markets. The RMR contract was ultimately reformed to eliminate this perverse incentive. To avoid similar perverse bidding incentives in the forward energy markets, it is imperative that the Commission find that the RUC availability payment should be rescinded for each MW of RUC capacity that is scheduled or dispatched for energy or awarded A/S capacity in a subsequent market.

### G. Scheduling, Billing and Settlement

#### 1. Bidding Rules For Sequential Markets

The CAISO proposes to institute the following bidding rules to facilitate the efficient operation of the market and the associated software, as well as reduce opportunities for market manipulation:

(1) The energy bid curve for supply resources must be a strictly monotonically increasing staircase function composed of not more than 20 segments, *i.e.*, the price for the next higher segment of output must be greater than the price for the previous segment of output. Similarly, the energy bid curve for demand resources must be a strictly monotonically decreasing staircase function composed of not more than 20 segments. This is a requirement for the overall bid curve of each resource regardless of the markets in which the different bid segments are bid into or selected. The function must be monotonically non-decreasing to ensure the convergence and optimality of the dispatch algorithm.[127]

(2) Accepted incremental bid energy prices associated with RUC and A/S capacity cannot be increased, and decremental bid prices associated with scheduled energy cannot be decreased in a subsequent market time frame. This applies to final Day-Ahead or Hour-Ahead energy schedules, A/S capacity awards and the energy bids associated with that capacity, and the energy bids associated with RUC commitments. The CAISO will, however, allow the incremental energy bid prices associated with unloaded A/S or RUC capacity to be lowered in a subsequent market if the supplier wishes to increase the likelihood of dispatch, and will allow decremental bid prices associated with scheduled energy to be increased in a subsequent market.

(3) Energy or capacity that is offered in one market time frame but not accepted by a buyer (*i.e.*, a demand bid for energy, or the CAISO in the case of A/S and RUC) is no longer a binding commitment on the part of the seller and may be offered in a subsequent market time frame at a higher price, or not offered at all in the CAISO Markets (subject, of course, to any applicable Must Offer obligation). In this case, the only restrictions are due to the structure of the energy bid curve (*i.e.*, monotonicity, and at most 20 segments.)

[127] If two non-contiguous segments of the energy bid provide the same price for different output levels, the algorithm could fail to produce a solution at all, or could reach a non-optimum solution.

(4) For the sake of clarity, the following proposed rules are written in terms of Hour-Ahead energy bid submission after final Day-Ahead schedules have been established. The same rules will apply to Real-Time energy bid submission after final Hour-Ahead schedules have been established, with certain obvious modifications to cover all the capacity and energy that was procured in both the Day-Ahead and Hour-Ahead IFM and RUC procedure.

(a) If the Hour-Ahead energy bids overlap only with the portion of the capacity that is covered by the resource's Day-Ahead accepted energy bids, the bid price of the decremental portion of the bid relative to the final Day-Ahead energy schedule cannot be less than the Day-Ahead bid price for the same energy.

(b) If the Hour-Ahead energy bids overlap with the portion of the capacity that is self-scheduled (without bids) in the Day-Ahead market, the bid price of the decremental portion of the bid relative to the final Day-Ahead energy schedule cannot be less than the bid floor which is currently –$30/MWh. [128]

(c) Generating units committed in the Day Ahead market (including A/S self-provision or award) or in the Day Ahead RUC may not de-commit without reporting an outage to the CAISO.

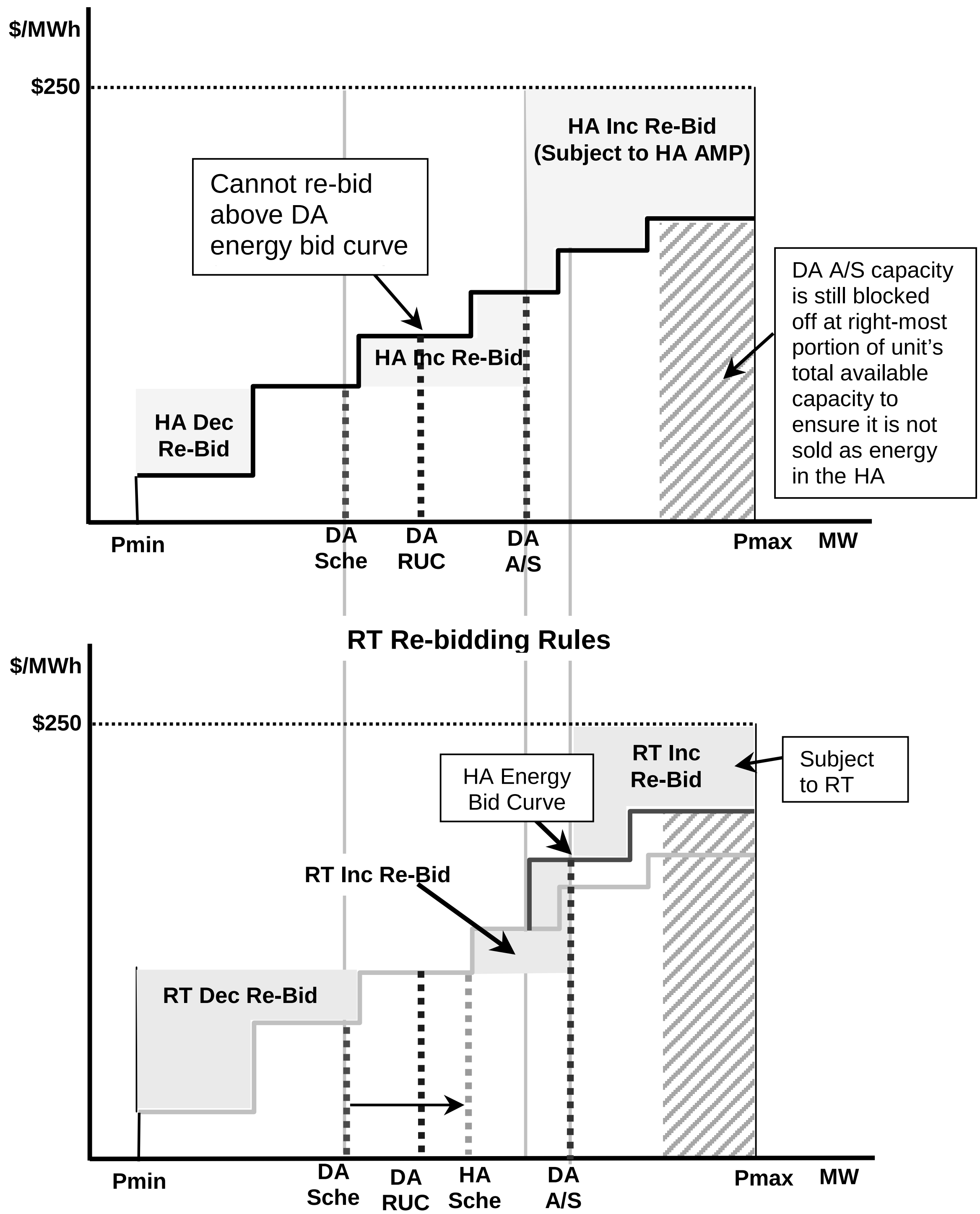
Figure 1 illustrates the re-bidding activity rules. As shown in the top part of Figure 1, the re-bid rule would allocate awarded Day-Ahead A/S capacity to the portion of the Day-Ahead energy bid curve that immediately proceeds the portion of the energy curve that is allocated to Day-Ahead RUC. Under this approach, the portion of the energy bid curve associated with Day-Ahead RUC and A/S could not be re-bid at a bid price higher than the Day-Ahead energy bid curve. However, the remaining capacity can be re-bid in the Hour-Ahead market at any level subject to AMP and keeping the curve monotonically increasing. If the unit is re-bid in the Hour-Ahead market and has a new Hour-Ahead schedule, the awarded Day-Ahead A/S capacity would be allocated to the Hour-Ahead energy bid curve immediately after the Hour-Ahead schedule as shown in the bottom part of Figure 2. The remaining capacity above this level could be re-bid in the Real-Time market subject to AMP and maintenance of a monotonically increasing curve. It should be noted that, if all of the capacity available to be sold in the Hour-Ahead market (*i.e*. Day-Ahead RUC capacity plus remaining capacity not committed to Day-Ahead A/S) had actually cleared the Hour-Ahead market, the Day-Ahead A/S capacity would be allocated to the right-most portion of the

[128] Because the bid floor is a "soft" floor, a bid below -$30/MWh would be allowed, but it would not be eligible to set the clearing price and would be subject to cost justification.

Hour-Ahead energy bid curve, and the unit owner would not be able to increase any portion of its Hour-Ahead energy bid curve in Real-Time.

The CAISO had originally proposed to enforce the re-bidding activity rules by allocating A/S awards to the right-most portion of a unit's energy bid curve, which would have effectively limited the re-bid opportunity of unselected capacity to the level of the energy bids associated with A/S awards. The CAISO subsequently determined that this approach would create an incentive for suppliers to bid the right most portion of their Day-Ahead energy bid curve at a high level to maximize their flexibility for re-bidding in subsequent markets. Rather than create such an incentive, the CAISO now proposes to enforce the re-bidding activity rules by allocating awarded Day-Ahead A/S capacity to the portion of the Day-Ahead energy bid curve that immediately succeeds the portion allocated to Day-Ahead RUC. Under this approach, the portion of the energy bid curve associated with Day-Ahead RUC and A/S cannot be re-bid at prices higher than the Day-Ahead bid prices. However, any remaining capacity of the resource can be re-bid in subsequent markets at any level, subject to AMP and maintaining the monotonic structure of the curve.

**Figure 1 –Proposed New Re-Bidding Activity Rules**




In Real-Time, the CAISO will still shift all A/S capacity to the right-most portion of the Energy Bid curve. The CAISO will do this after all re-bidding opportunities have been exhausted to preserve A/S capacity, *i.e.*, prevent such capacity from being Dispatched as Supplemental Energy.

The CAISO submits that its proposed bidding rules are just and reasonable. The bidding rules ensure a monotonically increasing bid curve that will mitigate potential gaming activities, yet afford sufficient flexibility to market participants. The underlying principles of the proposed bidding activity rules are as follows:

- Bid prices that are accepted in one market time frame are essentially contractual commitments and cannot be altered in a subsequent market time frame.[129] This applies to final Day-Ahead or Hour-Ahead energy schedules, A/S capacity awards and the energy bids associated with that capacity, as well as energy bids associated with RUC commitments. The CAISO will, however, allow the energy bid prices associated with awarded A/S and RUC capacity to be lowered if the supplier desires to increase the likelihood of Real-Time dispatch. However, energy bids associated with awarded forward energy schedules cannot be lowered because these are decremental bids which, if allowed to be lowered, could invite gaming (*i.e.* the DEC game).
- Energy or capacity that is offered in one market time frame but not accepted by a buyer (*i.e.*, a demand bid for energy, or the CAISO in the case of A/S and RUC) is no longer a binding commitment on the part of the seller and may be offered in a subsequent market time frame at a higher price. In this case the only restrictions that would apply are associated with the structure of the energy bid curve (*i.e.*, that it be monotonic and have, at most, 20 step segments.)

The Commission has recognized in the SMD NOPR that bidding limits mitigate market power. SMD NOPR at 273. The CAISO has proposed reasonable bidding limitations. The CAISO has proposed limited and reasonable bidding limitations that are necessary to guard against the exercise of market power and promote efficient least cost dispatch. Absent this provision, a supplier could submit a low energy bid curve in order to have its unit committed in the CAISO's RUC process and, then, once selected, ratchet up its energy bids for dispatch in the Real-Time market. With respect to preserving the optimality of dispatch, if market participants were free to increase energy bids associated with selected RUC and A/S capacity in subsequent market, the least-cost optimization that led to the selection of that capacity would essentially be meaningless. This approach is also consistent with the basic tenet of contract law that an accepted offer is a contract and such offers cannot be unilaterally revised to the detriment of the other party.

[129] When the CAISO accepts a supplier's incremental bid in one market, that acceptance constitutes an obligation for the supplier to furnish energy at an agreed-upon price that cannot later be raised. Likewise, when the CAISO accepts a supplier's decremental bid in one market, that acceptance constitutes an obligation for the supplier to purchase energy at an agree-upon price, a price that cannot later be lowered.

The CAISO's proposed bidding rules allow a reasonable 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 CAISO, can be re-bid into the CAISO'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 CAISO.

The CAISO's proposal is generally consistent with the bidding limitations in place in the Eastern independent system operators. Indeed, some of the re-bid rules offer greater flexibility to market participants. For example, ISO New England and PJM do not allow their market participants to change any part of their Day-Ahead energy bid – including the unaccepted part of the bid – if the unit is committed in the Day-Ahead market.

Moreover, in the July 17 Order, the Commission approved the CAISO's single energy bid curve proposal for hourly and 10-minute markets. July 17Order at P 131. The Commission further clarified its position on the re-bidding rules associated with the CAISO's single energy bid curve proposal in its October 11 Order:

> The Commission clarifies that a seller may increase or decrease its bid in the real-time market for capacity associated with that part of its bid curve that was not accepted in the hour-ahead market. The Commission also notes that for committed capacity, while a supplier may not submit higher bids, a supplier may submit lower bids in subsequent market to ensure the bid is scheduled.

October 11 Order at P 54. The Commission's clarification describes precisely some of the re-bidding rules proposed in this filing, in particular, the rule that unselected capacity can be re-bid at any price subject to market power mitigation provisions and maintaining monotonicity and the rule that energy bids from capacity that was previously committed through A/S or RUC can be lowered in a subsequent market but not increased.

### 2. Incorporating RMR Pre-Dispatch Into The New Bidding Structure

The CAISO anticipates it will continue to enter into annual RMR contracts for units that are critical for local reliability. RMR contracts are a means to ensure that generating units required to meet local reliability criteria remain economically viable and are not able to exercise local market power. Thus, RMR contracts work in concert with the local market power bid mitigation provisions to protect against the exercise of local market power.

As previously discussed (Section III.B.3), system and local market power mitigation procedures and determination of RMR dispatch levels will be performed in a sequence of pre-processing IFM runs in the Day-Ahead and Hour-Ahead time frames. These "Pre-IFM Reliability and Market Power Mitigation" runs (Pre-IFM-RMPM) will occur for the Day-Ahead market at 10:00 A.M., *i.e.*, after all bids and schedules are submitted to the CAISO. The Pre-IFM-RMPM runs will optimally dispatch resources as if they were procuring energy and ancillary services to meet 100 percent of the CAISO's demand forecast, rather than utilizing scheduled and bid demand. Using the forecast is appropriate because the needs for RMR dispatch and market power mitigation will ultimately depend on actual demand, not just on the demand scheduled and bid in the IFM. Of course, the actual IFM dispatch for forward scheduling and settlement purposes will be based on scheduled and bid demand after these Pre-IFM-RMPM runs are concluded.

RMR and LMPM requirements are determined by comparing the resource schedules derived from the Pre-IFM-RMPM-CC (*i.e*. a market run based on forecasted load with only competitive constraints enforced) and the Pre-IFM-RMPM-AC runs (*i.e*., a market run based on forecasted load with all network constraints enforced). For RMR units, the Pre-IFM-RMPM-AC schedule will be the RMR dispatch level if this schedule is greater than its Pre-IFM-RMPM-CC schedule. In this case, the bids associated with the RMR dispatch level will be set at the lower of the RMR cost-based bid or the unit's submitted market bid. The unit's market bid above the RMR dispatch level will be retained unless mitigated by System AMP. If the unit's Pre-IFM-RMPM-AC schedule is not greater than its Pre-IFM-RMPM-CC schedule, no RMR dispatch is necessary and the unit's original market bid will be retained in its entirety unless mitigated by System AMP. The final IFM run is based on submitted demand schedules and bids. All bids – mitigated and unmitigated, RMR and non-RMR – will be eligible to set the LMPs.

For the Hour-Ahead IFM and Real-Time pre-dispatch process, the following procedure will apply after bids have been submitted to the Hour-Ahead market. First, the CAISO will determine any incremental RMR requirements based on SCUC and dispatcher knowledge, insert the RMR price for these incremental quantities, and then notify RMR owners about this incremental dispatch through an ex-post dispatch notice.

The manner in which RMR dispatches are scheduled, bid, and settled represent a change from current practices. The current CAISO Tariff provisions pertaining to the bidding and scheduling requirements of RMR units operating under Condition 1 RMR contracts[130] were created in the context of a zonal

[130] There are two types of RMR contracts, Condition 1 and Condition 2, the main distinction being that under Condition 1 contracts, the RMR contract covers only a portion of the unit's annual fixed costs and the unit is allowed to participate in the market so that it can recover its remaining annual fixed costs. Under Condition 2 contracts, the RMR contract covers the entire

forward energy market, *i.e.*, the California Power Exchange (PX). Under the current provisions, the CAISO issues RMR pre-dispatch instructions to Condition 1 RMR units prior to the Day-Ahead market, and unit owners can comply with these instructions by electing either a "contract path" or "market path." When the PX existed, a unit owner who elected the contract path would be required to bid the RMR pre-dispatch quantity into the PX Day-Ahead Market at $0/MWh (*i.e.*, as a price-taker) and would receive the variable cost payment specified in the RMR contract.[131] If the unit owner elected the market path, it would forfeit the RMR variable cost payment and would instead rely on the market to recover its variable costs. A unit owner that elected the market path was free to bid the RMR pre-dispatch quantity into the PX Day-Ahead market at any price, or not bid the pre-dispatched quantity into the Day-Ahead market at all. Regardless of whether the unit owner elected the contract or market path, any amount of Day- Ahead RMR dispatch that was not scheduled in the CAISO Day-Ahead market was required to bid into the "Day Of" PX market as a $0/MWh price taker bid or be scheduled as a bilateral contract in the ISO's Hour Ahead market.

Because the PX market was a zonal market, there was no opportunity for the RMR unit owner choosing the market path to exercise local market power through bidding excessively high. If the unit owner bid excessively high into the PX Day-Ahead market, its energy would likely not be selected, and it would then be required to bid into the subsequent PX "Day Of" market as a price taker or submit an Hour-Ahead bilateral schedule that equaled the RMR dispatch quantity. The contract and market path options remain under the CAISO's current market design despite the demise of the PX market. Currently, RMR unit owners electing the market path for a Day Ahead RMR pre-dispatch instruction must self-schedule that quantity in the CAISO's Day-Ahead or Hour-Ahead market.

If the CAISO were to retain the same "market path" provisions for RMR dispatches under the Phase III market design, unit owners that elect the market path for Day-Ahead RMR pre-dispatches would be allowed to bid the pre-dispatched quantity into the CAISO's Day-Ahead nodal energy market. Since the CAISO's Day-Ahead energy market would enforce the full network model, providing such an option for RMR unit owners would enable them to exercise local market power by submitting high bids for their RMR dispatch quantities. While it may be possible to mitigate this local market power through the application of the LMPM provisions, the CAISO believes this would defeat the

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annual fixed cost, the unit is precluded from participating in the market and is under complete dispatch control by the ISO.

[131] The RMR owner would also receive a payment from the market for the value of the energy produced by the RMR unit, but would then credit back this payment under the terms of the RMR Contract.

very purpose of the RMR contracts, which is to ensure that units critical for local reliability are available and not able to exercise local market power.

Therefore, the CAISO proposes to eliminate the contract and market path options for RMR units as specified in Section 2.2.12.2 of the CAISO Tariff and provide a single option that has desired elements of both. Specifically, the CAISO will determine RMR dispatch quantities using the Day-Ahead, Hour-Ahead, and Real-Time procedures described *supra*. The CAISO will assign bids to these RMR dispatch quantities equal to the lower of the unit's submitted market bid (if applicable) and the RMR contract variable cost. These assigned bids will be available for dispatch and eligible to set the LMPs in the subsequent market. All Condition 1 units will be able to keep market revenues in excessive of the RMR contract variable cost. There will be no option for different payments (*i.e.*, contract versus market path). This approach strikes a compromise in that Condition 1 unit owners are restricted from submitting bids above their RMR contract variable cost applied to their RMR dispatch, but are able to earn and keep market revenues above their contract variable cost. Under this approach, excess revenues for Condition 2 units are credited toward their fixed cost compensation as is done currently.

### 3. Self-Scheduling

MD02 allows SCs to submit both self-schedules and bids to the IFM. A self-schedule is a preferred level of energy demand or supply, or both (in MW), without accompanying DEC bids.[132] Lacking DEC bids, self-schedules will initially be fixed at their submitted levels and will not be reduced in the economic adjustment phase of the IFM, in which the IFM attempts to resolve congestion and balance supply and demand on the system using economic bids. If congestion cannot be fully resolved, or supply and demand cannot be balanced using only economic bids, self-schedules may be reduced in accordance with the hierarchical sequence described in Paragraph Nos. 31-34 of the amended Comprehensive Market Design Proposal. Whether or not they are adjusted in the IFM, any quantities of self-scheduled demand and supply that are accepted in the CAISO's final forward schedules will be settled as price takers.[133]

Self-schedules, except for ETC and CRR schedules, need not be balanced when submitted. Moreover, even if a self schedule is initially balanced

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[132] For example, if the SC submits a preferred operating level for a supply resource that is above its minimum operating level ("P-min"), and also submits DEC bids over the range from P-min up to the preferred operating level, the IFM treats this the same as if the SC had submitted an incremental energy curve without a preferred operating level. Accordingly, the IFM will dispatch the resource at the optimal level for the given load and system conditions. Thus, the absence of DEC bids defines the self schedule and removes it from the economic adjustment process of the IFM.

[133] The risks associated with being a price taker for congestion charges in the IFM can be hedged if the SC holds CRRs corresponding to an initially balanced self schedule.

when submitted, the IFM will not try to keep it in balance in the event of non-economic adjustment unless it is an ETC schedule.

The CAISO recognizes that allowing self schedules will likely reduce the liquidity of the forward congestion management market relative to a market in which all schedules are submitted with energy bid curves over their entire range. However, self scheduling is appropriate in the CAISO markets for a number of reasons. First, many market participants own their own generation resources or have generation resources under contract to serve their own load, and wish to schedule these resources to serve their own load without the risk that such resources will be used to serve some other entity's load. Self scheduling, in combination with the Day Ahead demand-side CRR scheduling priority, enables them to achieve this objective. Second, while market participants generally acknowledge that all schedules must be subject to the CAISO's forward congestion management process, they argue that participation in the forward energy market should be voluntary not compulsory. Third, some parties operate "Must Take" or "Must Run" resources that either have no economic basis for curtailment or are required to operate at specific levels for non-economic reasons. Self scheduling achieves the latter objectives as well.

During the Working Group discussions, several market participants argued that self scheduling is not necessary because SCs can submit price-taker bids (*i.e.*, bids at the level of the damage control bid cap) and accomplish the same result. Others pointed out that it might be problematic to attempt to accomplish self-scheduling through the use of price-taker bids given the extent of the CAISO's mitigation measures. They argued that energy bids designed to prevent energy trading or to achieve curtailment priority for congestion management likely might trigger the AMP mitigation mechanism. Others argued that the $250/MWh bid cap (rather than a much higher level) may be used by different market participants for a variety of purposes and, thus, would not provide an adequate distinction as needed for self-scheduling. Several of these participants requested the option to set a flag on their preferred schedules that would explicitly distinguish self schedules. The majority of market participants, however, rejected the use of a flag to distinguish self-schedules, claiming that such a flag would amount to preserving the market separation rule, albeit on a voluntarily basis. The CAISO is similarly concerned about retaining any vestige of the market separation rule, particularly because of its adverse effect on the volume of bids for forward congestion management.

After weighing the various arguments, the CAISO and the stakeholders arrived at what should be an effective solution: to allow self-scheduling as defined above, but not preserve balanced self-schedules when they must be adjusted for congestion management. Self-scheduling of a load or a supply resource simply gives that load or resource a higher probability of being scheduled without having to compete with other loads or resources that submit bids. At the same time, it exposes those loads and resources to whatever prices result from the IFM and gives them no ability to set prices. Thus, the problematic aspect of self scheduling for efficient forward markets is not self scheduling *per se*, but the balanced schedule requirement.

When congestion exists, prices will generally be set by the economic energy bids submitted by resources and loads. However, when these bids are exhausted, congestion will be managed by adjusting self-schedules based on formulaic, non-economic bid values that are inserted as a device to indicate scheduling priorities. Details of the proposed priorities are provided in Paragraph Nos. 33-34 of the amended Comprehensive Market Design Proposal. In cases where self-schedules have to be adjusted in the IFM because of insufficient market bids, prices at such locations will be determined administratively based on the Damage Control Bid Caps.

While some participants are content for self schedules to be treated as price takers for congestion management, others want to be able to: (1) specify limit prices for congestion in association with a balanced self schedule (such that when congestion costs exceed the limit their self-schedules would be reduced in a balanced way), or (2) provide conditional energy bids on a balanced self-schedule that would only be used by the CAISO under certain conditions (for example, based on physical congestion or nodal price differences). The CAISO has pointed out to market participants that accommodating these desires not only would add significant complexity to the IFM design, but also would exacerbate the well-known inefficiency of the market separation rule by trying to maintain the balance of individual schedules while managing congestion on a full network model. The CAISO's proposal strikes an effective balance by allowing market participants to opt out of the CAISO's forward energy market and schedule their own resources to serve their own load, while avoiding the deleterious effects associated with trying to maintain individually balanced schedules.

### 4. Changes to the Hour-Ahead and Real-Time Markets

#### a. Integrating LMP Into The Real-Time Market

A crucial feature of the LMP market design is the geographic granularity used for scheduling and financial settlement of loads. As noted above, SCED in Real Time is being implemented as the primary design element of CAISO Amendment No. 54. The initial implementation will feature the CAISO's current three-zone network model. With the introduction of the full network model into the integrated forward market in MD02 Phase III, the full network model will also be installed for use with Real-Time SCED. In other words, in Phase III, the CAISO will implement the full network model in the forward energy and congestion management markets, as well as in the Real-Time market. This will ensure that pricing and transmission allocation in the Real-Time are consistent with pricing and transmission allocation in the Day-Ahead.

### b. Timing of the Hour-Ahead Market

In its May 1 Filing, the CAISO proposed to revise the Hour-Ahead time line. Rather than closing the Hour-Ahead market to submissions at two hours prior to the beginning of the operating hour as is done today (referred to as T-120 minutes), the CAISO proposed to close the market at T-60, and to simultaneously close bid submissions to the Real-Time (Supplemental Energy) market.[134]

Based on input from stakeholders and a reassessment of the feasibility of running all elements of the IFM between T-60 and Real-Time, the CAISO has decided to withdraw its original proposal to move the Hour-Ahead market up to T-60 and to close the Real-Time market at the same time.[135] Instead, the CAISO now proposes to close the Hour Ahead IFM at T-120, to publish final Hour-Ahead schedules at T-90, and close the real-time market at T-60. This will allow a 30-minute re-bid period between final Hour-Ahead schedules and the close of Real-Time bid submissions.

The CAISO submitted its original proposal in response to what it believed was universal support for such change. After several iterative discussions with stakeholders, that proved not to be the case. Some market participants expressed a concern about not having an opportunity to revise their Real-Time Energy bids after reviewing their final Hour-Ahead schedules as established in the CAISO's Hour-Ahead market. They argued that a re-bid period of roughly 30 minutes between the CAISO's publication of final Hour-Ahead schedules and the close of Real-Time bid submissions was necessary. Unfortunately, such an approach is not compatible with moving the Hour-Ahead market closer to Real-Time, and would require closing the Hour-Ahead market at approximately T-120, where it is today.

Accordingly, the CAISO has decided to retain the T-120 timing of the Hour-Ahead market. The CAISO sees the issue as a simple choice between (1) moving the Hour-Ahead market closer to Real-Time and eliminating the

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[134] The May 1 Filing was based on the idea that a window for Energy trading as late as 60 minutes before the start of the operating hour would provide an opportunity for resources to be dispatched for hourly periods, with an hourly price commitment and timing near to Real-Time. In addition, the CAISO believed that the trading opportunity created by this Hour-Ahead timeline would satisfy the needs of inflexible resources for a 60-minute dispatch. Further, the CAISO believed that closing bid submissions at approximately T-60 would provide the CAISO with adequate time to run the necessary processes and procedures that it must undertake.

[135] The CAISO's experience running AMP over the past months suggested that the CAISO might need to modify the original T-60 proposal so as to close Hour-Ahead bid submissions prior to the close of Real Time bid submissions. This would allow sufficient time for operations personnel to receive and process the Hour-Ahead information by the time they get the Real-Time information.

current re-bid period, or (2) retaining the re-bid period and keeping the Hour-Ahead market timeline roughly where it is today. Either option is compatible with the comprehensive MD02 design. The CAISO has selected the latter option.

#### c. Real-Time Pre-Dispatch

The CAISO anticipates the need for a Real-Time pre-dispatch to occur at approximately T-45, to enable the CAISO to give Real-Time dispatch instructions to supply resources that will be needed for the coming operating hour but are not five-minute dispatchable. This is consistent with the CAISO's earlier MD02 filings. Pre-dispatch quantities will be calculated taking into account the expected real-time imbalance. Imports that are pre-dispatched for the entire hour will be guaranteed their bid price, but cannot set the five-minute MCP.[136] To the extent the simple average of the five-minute prices for the hour falls below their bid price, the difference will be paid as uplift. In-state generation that is pre-dispatched due to start-up limitations and has a minimum operating level that must be sustained for a minimum run time is eligible to set the MCP so long as there is a system need for the energy. If system conditions change and the in-state generation is no longer needed, but must remain on-line at a minimum operating level to satisfy its minimum run time constraint, the resource will still be guaranteed at least its bid price but will no longer be eligible to set the MCP.

### 5. Ramp Rates

The CAISO proposes that the scheduling and dispatch software will support the following three ramp rates:

(1) **Operational ramp rate function**. As proposed in Amendment No. 54, the CAISO will accommodate SCs bidding an operational ramp rate function of up to 10 ramp rates over the entire operating capacity of the resource. The operational ramp rate function will be submitted with the preferred schedule and will be validated to be between a minimum and a maximum operational ramp rate function registered in the Master File. The operational ramp rate function will be used to limit hourly schedule changes in the forward markets and to limit the amount of Supplemental Energy that can be dispatched in Real-Time. The ramp rate function is fixed throughout the day and can only be changed (by notifying the

[136] The CAISO recognizes that, because practically all import bids to the Real-Time market are not dispatchable within the hour and therefore must be pre-dispatched for the entire hour, disallowing such bids from setting the five-minute MCPs in Real-Time will be problematic in terms of determining Real-Time prices when there is congestion at the inter-ties. Therefore, the CAISO will be considering modifications to the Real Time Market pricing rules for import bids so that pre-dispatched bids could be eligible to set the five-minute price so long as there is a system need for their energy. This modification would be consistent with the pricing rules for internal generation that have minimum load level and minimum run time constraints.

CAISO via SLIC) when something occurs to alter the ramping capability of the unit.

(2) **Operating Reserve ramp rate.** For Operating (Spinning and Non-Spinning) Reserve, SCs shall bid a single ramp rate value, distinct from the Operational ramp rate function. The Operating Reserve ramp rate will be submitted with the preferred schedule and will be validated to be between a minimum and maximum Operating Reserve ramp rate specified in the Master File. The Operating Reserve ramp rate will be used in procuring Operating Reserves in the forward markets and for dispatching Energy from Operating Reserve for contingencies[137] in Real Time. This ramp rate is fixed throughout the day and can only be changed (by notifying the ISO via SLIC) when something occurs to alter the Operating Reserve ramping capability of the unit.

(3) **Regulation ramp rate.** There shall be a single regulating ramp rate value. The regulating ramp rate will be submitted with the preferred schedule and will be validated to be between a minimum and a maximum regulating ramp rate registered in the Master File. The regulating ramp rate will be used to procure Regulation Up and Down in the forward markets and to dispatch Energy from the resource when the resource is providing Regulation. Resources must bid the same ramp rate for Regulation Up and Regulation Down for the same operating period. The ramp rate is fixed throughout the day and can only be changed (by notifying the ISO via SLIC) when some physical change alters the regulating capability of the unit.

In Amendment No. 54, the CAISO has proposed to create a "No-Pay" charge to account for differences between the amount of capacity awarded in the forward markets and the amount actually available for Real-Time dispatch as determined by the operational ramp rate. Because the CAISO may be dispatching Energy from Operating Reserve capacity based on the Operating Reserve ramp rate, not the operational ramp rate, this feature will be modified when the IFM is implemented so that the "No-Pay" adjustment will apply only when the Operating Reserve ramp rate is changed after it was used to procure A/S capacity. If the Operating Reserve ramp rate is changed between the Day-Ahead and Hour-Ahead markets, the SC will be required to buy back any Day-Ahead Ancillary Service capacity sold based on the previous Operating Reserve ramp rate. The Operating Reserve ramp rate will be used to procure spinning reserve and non-spinning reserve in the IFM. The Regulation ramp rate will be

[137] Energy may also be Dispatched from Operating Reserve capacity in economic order (unless such capacity has been designated as "contingency only") under those conditions, the Energy would be Dispatched at the operational ramp rate, not at the Operating Reserve ramp rate.

used to procure Regulation in the IFM and to dispatch the unit in Real-Time if the unit is on regulation (*i.e.*, dispatched by AGC), but if the resource is not on regulation the Operational ramp rate function will be used for real-time dispatch. In Real-Time a 10-minute available capacity quantity will be calculated based on the relevant real-time dispatch ramp rate. This quantity will be compared with the amount of capacity that was awarded A/S and any differences will be charged a weighted average rate calculated from the ASMP and the A/S capacity procured in the forward markets, thus creating a "No-Pay" mechanism for unavailable capacity.

### H. Honoring Existing Transmission Contracts

#### 1. Need for a Revised Proposal for Honoring ETCs

The CAISO's new proposal for honoring ETCs departs significantly from the proposal in the May 1 Filing. The need for a new proposal became apparent with the CAISO's growing recognition of the severe complexities and market impacts associated with the CAISO's original proposal. In particular, there are significant problems associated with maintaining the CAISO's existing approach of fully reserving transmission capacity for ETCs in the Day-Ahead market in the context of a LMP congestion management approach which uses a fully detailed network model. Specifically, implementation of the prior proposal would have adversely affected both the availability of CRRs for hedging congestion costs and the day-to-day availability and cost of transmission for non-ETC grid users. In addition, it would have increased the complexity and costs associated with the CAISO's responsibilities in managing ETC usage of the grid.

In response to growing concerns about the feasibility of the prior proposal, the CAISO developed the approach proposed herein, which would continue to honor ETC rights fully, but would do so without withholding unscheduled ETC capacity from the market (and without reducing the firmness of accepted non-ETC schedules). The new proposal also transfers ETC management responsibility from the CAISO to the parties to those contracts.

The CAISO acknowledges that the new ETC proposal was only presented to stakeholders in the last few months and that additional discussion and collaborative work are needed to refine some important aspects of the proposal. As noted elsewhere in this document, the CAISO's ETC proposal is one of a small group of MD02 design elements slated for continued development with stakeholders. The CAISO submits that those few ETC details that are not finally resolved by the instant filing, while important to the efficient functioning of the MD02 design, will not have any impact on the design itself. Because any uncertainty regarding the outstanding issues will not materially affect the other elements of the ETC proposal and the MD02 proposal generally, the Commission should not defer ruling on those aspects of the ETC proposal that have been finalized. The CAISO will report to the Commission at a later date regarding the final details for addressing certain ETC issues.

### 2. Impacts of ETCs

For its entire history, the CAISO has struggled with the problems of trying to provide uniform, non-discriminatory, and open access transmission service while still honoring the special provisions of grand fathered ETCs. Providing transmission service to ETC holders under a different set of market rules than those applicable to all other grid users has led to significant inefficiencies.

Paper or "phantom" congestion is one well-recognized inefficiency that results from the CAISO's current approach to honoring ETCs. Phantom congestion occurs in California because the CAISO, in the Day-Ahead scheduling process, withholds transmission capacity from the market for potential use by ETCs, even though significant quantities of that capacity may go unused by the ETC holder in Real-Time. This practice is the CAISO's current mechanism for ensuring that it can honor ETC provisions that permit ETC holders to change their schedules after the forward markets close and forward market schedules are finalized (typically quite close to Real-Time). As a result of this practice, other users of the system are often precluded from scheduling in the forward markets or charged in the forward markets for congestion that does not actually exist in Real-Time. In other words, the reservation of unscheduled capacity for ETCs causes transmission paths to be artificially congested in the forward markets because the market schedules submitted across those paths are greater than the transmission capability that is available after ETC reservations have been withheld, yet may be far below the paths' actual physical transfer capability.

CAISO analysis shows that, although phantom congestion has been reduced over the past four years, it remains a significant feature within the CAISO Control Area, particularly over a few key external and internal paths (including the California-Oregon Intertie, *i.e.*, COI), Path 15, Path 26 and Palo Verde. *See* Attachment G hereto. The CAISO's Department of Market Analysis ("DMA") has estimated that, if market power impacts are considered, it is reasonable to expect that the annual benefits of eliminating phantom congestion could well be in the hundreds of millions of dollars. See Prepared Direct Testimony of Keith Casey (Exhibit No. ISO-23) at 5-7 and Exhibit No. ISO-24 filed in Docket No. ER00-2019 on February 14, 2003.[138] The CAISO's analysis shows that making the full ETC capacity available in the Day-Ahead market would substantially reduce Day-Ahead and Hour-Ahead congestion. The full integration of ETC capacity into Day-Ahead scheduling would (1) largely eliminate Day-Ahead congestion on COI, and (2) significantly reduce Day-Ahead congestion on Path 15 (both directions), Path 26 and Palo Verde Branch Group.

[138] The CAISO hereby incorporates by reference Exhibit Nos. ISO-23 though ISO-25 filed in Docket No. ER00-2019.

The CAISO also notes that, as a result of phantom congestion, in July 2001, Morgan Stanley Capital Group ("Morgan Stanley") filed a Section 206 complaint against the CAISO, alleging that the CAISO's preferential treatment of ETC contract transmission was discriminatory. Morgan Stanley eventually withdrew this complaint in January 2003 under the expectation that the CAISO's MD02 market design and/or the Commission's proposed Standard Market Design would address this problem. *See* January 22, 2003 Notice of Withdrawal of Complaint, Docket EL01-89.

Phantom congestion produces several detrimental impacts. First, it results in an inefficient dispatch of generation resources because higher cost generation necessarily must be substituted for lower cost generation to relieve the phantom constraint. Thus, phantom congestion unnecessarily raises total production costs. Second, phantom congestion on the inter-ties raises the cost of energy to California LSEs because they are unnecessarily restricted from purchasing lower cost imports due to phantom constraints. Phantom congestion also reduces market competition because fewer imports are able to compete with internal supply resources. Third, phantom congestion creates incorrect price signals for investment in transmission upgrades and the location of new generation. Fourth, the ability to create phantom congestion by over-reserving ETCs can be used by market participants to exercise market power in the congestion management market. For example, if an ETC rights holder also owned FTRs, the holder could drive up congestion prices by creating phantom congestion and then realize the profits from this strategy through its FTR position.

In addition to these market impacts, the CAISO has borne a heavy burden administering a large number of separate ETCs, many of which have non-standard and non-uniform terms and conditions. From the beginning of CAISO operations it was not feasible to create customized procedures to accommodate the various ETC terms and conditions. Instead, the CAISO has had to develop standard rules and procedures that are broad enough to encompass the entire set of ETCs, which inevitably has resulted in some ETCs enjoying benefits beyond what they received prior to CAISO start-up. For example, the CAISO currently allows ETC rights holders to submit schedule changes up to 20 minutes before the start of the operating hour, even though not all ETCs allow this much flexibility.

Having different sets of rules by which market participants can schedule and use the grid creates inefficiencies and inequities that undermine the efficient allocation and use of the grid. Moreover, all of the problems identified above promise to increase in severity if the CAISO tries to maintain the current approach to honoring ETCs, when the FNM is used for congestion management. For example, under MD02, the CAISO will have to: (1) model ETC rights in terms of specific sources and sinks relative to the FNM; (2) perform a simultaneous feasibility test to determine the collective utilization of grid capacity by ETC rights and then withhold this capacity from the CRR release process; (3) calculate, on a day-to-day basis, the collective grid capacity that must be withheld due to ETC reservations and remove this from allocation through the IFM; and (4) create new software to calculate adjustments to ETC rights when transmission facilities are derated or out of service. The CAISO expects items (1) to (3) in particular to exacerbate the adverse impacts of ETCs on the availability and cost of transmission to market participants.

To be more specific, the continued occurrence of phantom congestion under MD02 would undermine a primary reason for the MD02 market redesign, namely, ensuring consistency in transmission allocation and pricing between the forward and Real-Time markets. A crucial, desirable effect of such consistency is that it creates strong incentives for market participants to avoid the uncertainty and volatility of Real-Time by making forward arrangements and scheduling most of their transactions on a day-ahead basis. However, when phantom congestion occurs, it means that significant quantities of transmission capacity will become available in Real-Time that were not available in the forward markets. This will tend to make Real-Time more attractive by reducing the risk of Real-Time transmission unavailability and the volatility of Real-Time prices.

In light of the problems associated with ETCs, the CAISO has expended considerable time and effort exploring the development of a solution that would satisfy the following goals: (1) minimize the adverse impact of ETCs on the CAISO's markets; (2) reduce the CAISO's ongoing role in and responsibility for managing ETCs; and (3) eliminate "phantom" congestion.

### 3. Details of the Current Proposal for Honoring ETCs

Although the CAISO would prefer that all ETCs be converted to CRRs, the CAISO recognizes that full conversion of all ETCs will not likely occur until some time after the MD02 design is implemented. Accordingly, the MD02 proposal provides a method whereby the CAISO will continue to honor ETC rights. In particular, the CAISO's proposal is designed to (1) preserve the scheduling priorities that ETC rights holders enjoy under the terms of their contracts, while treating ETC schedules as much as possible like the schedules of all other grid users, and (2) minimize the inefficiencies created by the current practice of withholding unscheduled capacity from the forward market allocation process.

As noted at the beginning of this section, several details of the ETC proposal will be the subject of continuing discussion and development with stakeholders. To be more specific, the CAISO's ETC proposal can be thought of as having three main components: (1) ETC scheduling; (2) validating that ETC schedules submitted to the CAISO's IFM are consistent with the rights holders' contractual rights; and (3) responsibility for CAISO charges associated with ETC schedules. The CAISO believes that its proposal for (1) is crucial for the elimination of phantom congestion, and the basic principle of not reserving unscheduled ETC capacity is fundamental to the new proposal. Accordingly, the

Commission should promptly approve this aspect of the CAISO's filing. In contrast, the proposals identified in (2) and (3) allow some room for development of the details, as long as the final proposal achieves the CAISO's stated objectives. The following discussion should clarify these points.

### a. ETC Scheduling

Under the MD02 proposal, ETC rights holders will continue to submit balanced schedules to the CAISO Markets and will be given scheduling priority over other users of the CAISO Controlled Grid in the Day-Ahead and Hour-Ahead markets, in accordance with the provisions described in Section 2.2.5 of the amended Comprehensive Market Design Proposal and to the extent such schedules conform to the rights holders' contractual rights. In particular, in the Day-Ahead market, valid ETC self schedules will be the last to be adjusted in the event that non-economic adjustments are required to relieve congestion. However, in contrast to today, the CAISO will not reserve any transmission capacity for ETCs beyond the capacity used by their Day-Ahead schedules. In the Hour-Ahead market, ETC schedule changes will be given priority over all other Hour-Ahead schedule changes and will be accepted as fully as possible without modifying final Day- Ahead schedules.[139] Any portion of Hour-Ahead ETC schedule changes that cannot be accepted in the Hour-Ahead market will be accepted as Real-Time schedule changes. In addition, ETC rights holders will be able to submit, and the CAISO will accept, further schedule changes after the Hour-Ahead market closes in accordance with the ETC rights. In Real-Time, the CAISO will re-dispatch non-ETC resources relative to their final Hour Ahead schedules as needed to accommodate valid real-time ETC schedule changes.

The load side of ETC schedules will be scheduled and settled at specific network nodes or, if applicable, the interfaces of a metered subsystem (in contrast to the load side of non-ETC schedules, which will be scheduled and settled at the appropriate Load Aggregation Zone).

### b. Validation of ETC Schedules

As described above, incorporation of ETC management into the LMP congestion management approach will impose significant complexities and

[139] There is one exception to this proposed rule, specifically, the transmission capacity on the California Oregon Transmission Project ("COTP"), which is one line of the three-line California-Oregon Intertie (COI). COTP represents a situation where the CAISO is the operator of the transmission facilities and is responsible for their reliable operation in Real-Time. However, the COTP facilities are not part of the CAISO controlled grid and, therefore, the CAISO cannot control how capacity on these facilities is allocated to users. In order to continue to respect this distinction under the new ETC proposal, the CAISO will give COTP schedules the highest priority in Day Ahead and will NOT release unscheduled COTP capacity to the market, but will reserve the full amount of COTP capacity for COTP schedule changes in Hour Ahead and Real time, unless some alternative agreement is reached with COTP owners.

burdens on the CAISO. The CAISO asserts it is appropriate to transfer these management responsibilities to the contracting parties. Specifically, the PTOs with which ETC rights holders have contracted, or other designated SCs for the ETCs as determined by the parties, will be responsible for certifying to the CAISO that submitted ETC schedules and schedule changes are consistent with the contractual rights of the ETC rights holder. What remains to be determined is whether a party other than the PTO would be capable of assuming this responsibility in a manner that assures ETC schedules will fully and consistently comply with the ETC terms and conditions. Regardless of who performs this function, ETC schedules may be subject to periodic review by the CAISO or audit by an independent third party, but will not be validated for compliance with contract terms on a daily basis by the CAISO.

#### c. Responsibility for CAISO Charges

Except for the exclusion of ETCs from the load aggregation provisions, all ETC schedules and Real-Time deviations will be treated the same as those of other CAISO grid users in the settlement process and, thus, will be assessed all applicable charges, *e.g.*, congestion charges and Real-Time uninstructed deviation penalties. The CAISO recognizes that schedules and energy flows covered by ETC rights are generally exempt under their contract terms from some charges, such as congestion and transmission losses, that arise from use of the transmission system. In order to facilitate the allocation of cost responsibilities, the CAISO proposes to work with the affected parties to develop an appropriate mechanism. For example, it may be effective to provide special Scheduling Coordinator IDs ("SCIDs") for the designated SCs to use for scheduling and settlement in conjunction with the use of ETC rights.

Because of the exposure of ETC schedules (which, like other schedules, cause congestion) to congestion charges, the CAISO proposes to work with affected parties to develop an appropriate hedging mechanism. For example, it may be effective to allocate CRR Obligations to loads served under ETC rights in a manner similar to allocation of CRRs to other loads in the CAISO Control Area. The one distinction is that CRRs allocated to ETC loads would have actual load locations as their sink consistent with the requirement for ETC schedules to specify actual load locations rather than the load aggregation zones that will be used by non-ETC loads. Regardless of the mechanism employed, to the extent PTOs are exposed to CAISO charges associated with ETC schedules, the CAISO will support PTO filings at the Commission for recovery of all costs prudently incurred in connection with the scheduling and management of ETCs.

### 4. Some Stakeholder Concerns About the New Proposal

Some parties have expressed concern that this new proposal will place a severe real-time burden on CAISO operators by requiring them to accommodate real-time changes to ETC schedules instead of simply reserving capacity for the ETCs in the Day Ahead Market. However, CAISO's operators do not see this as a large burden for the reasons set forth below. First, for ETCs that utilize only transmission capacity within the CAISO control area, the Real-Time security-constrained economic dispatch will see the ETC changes as Real-Time imbalances and will automatically re-dispatch resources as needed to meet load in the most efficient manner, taking into account transmission constraints and generator performance. Thus, managing internal Real-Time ETC changes is not different from managing any other real-time imbalances.

Second, for ETCs that utilize inter-tie capacity, the CAISO will rely on the Real-Time inter-control area check-out process, which occurs approximately 30 minutes before the start of the operating hour. This is the process by which adjoining control areas determine the net line flows on all transmission pathways connecting them, based on the firm energy schedules they have established in each of their systems. At the completion of the check-out process, two adjoining control areas must show the same flows over each common inter-tie. Thus, when an ETC rights holder submits a Real-Time schedule change to the CAISO that results in excessive flow over an inter-tie, the check-out process will reveal which SC's final Hour Ahead CAISO schedule does not have a firm schedule of equal magnitude in the other control area, and this schedule will be reduced to accommodate the ETC change (assuming that the ETC rights holder does have a firm schedule in the other control area). The CAISO can rely on an already-existing procedure to determine the appropriate schedule changes to make to accommodate real-time ETC changes.

Another argument raised by some parties is that the remaining lifetime of many ETC contracts is too short to justify so dramatic a change to the CAISO's procedures for honoring ETCs. These parties argue that with the reduction in ETC capacity due to contracts expiring over the next few years, the frequency and magnitude of phantom congestion should no longer be a significant problem. While there may be some validity to this point, the point actually reinforces the CAISO's arguments for adopting the new ETC proposal. Even with a reduction in phantom congestion, the CAISO cannot reduce the cost and complexity of implementing new procedures and systems to deal with Day- Ahead reservations of unscheduled ETC capacity in the LMP context as long as the CAISO must handle some quantity of ETC reservations, no matter how small. Because substantial ETC expiration is expected over the next several years, that is all the more reason not to create elaborate and costly means to manage ETC reservations. Rather, this supports implementation of the simpler new approach.

In conclusion, the CAISO's proposal has numerous benefits. First, phantom congestion will be eliminated on all tie points with the exception of the COTP. This outcome should further the Commission's efforts to promote the efficient allocation of transmission service to those that value it the most. Second, the CAISO's proposal fully honors the contractual rights of ETC holders while mitigating the adverse impact of such rights on other market participants. Third, the proposal creates an incentive for ETC right holders to schedule in the Day-Ahead Market because any Real-Time schedule changes will be subject to all

CAISO charges related to the Real-Time Market. Fourth, the CAISO's proposal will reduce MD02 implementation costs by eliminating the need for the ETC Calculator. Instead, the CAISO will rely, on the PTOs or designated SCs to verify that submitted ETC schedules are consistent with their contract terms (with the exception of COTP, whereby COTP rights simply equal to 1/3 of COI OTC). Finally, the CAISO believes that this proposal is consistent with the approach the Commission put forth in the SMD NOPR regarding ETCs and achieves the Commission's stated objectives. Accordingly, the Commission should approve the CAISO's proposed treatment of ETCs because it will support and enhance the effectiveness of the MD02 market redesign by resolving a problem that has plagued the CAISO since start-up.

### I. Demand Response

Section 2.6 of amended Comprehensive Market Design Proposal outlines Demand bidding (including dispatchable Participating Load) into the CAISO's forward Energy, RUC, Ancillary Services and Real-Time markets. As noted in Paragraph 127, the CAISO looks to state agencies to design and implement special demand response programs. The CAISO desires to provide the market structure that will facilitate these programs. Implementation details are significant and will require continued dialogue with the major LSEs and state agencies before submitting final Tariff language.

The CAISO's MD02 proposal recognizes that demand response is a vital ingredient in the design of a well-functioning electricity market. Although the implementation of retail demand programs is ultimately the responsibility of load-serving entities and state agencies, the MD02 design supports these programs by establishing needed market infrastructure and incentives,[140] including transparent, Day-Ahead hourly prices and improved opportunities for load to participate in CAISO Markets as resources that augment and compete with supply resources. These opportunities, which require loads or aggregated load entities to execute a Participating Load Agreement to establish sound mechanisms for data and settlement flows between the CAISO to SCs, are set forth in detail in Paragraphs 123-129 of the amended Comprehensive Market Design Proposal.

### J. Impact of MD02 On Metered Subsystems

The proposed treatment for Metered Subsystems ("MSS") under the MD02 market design is set forth in Paragraphs 147-157 of the amended

[140] For example, the end-use load can only get a benefit from the wholesale price if it is allowed by the CPUC or the local regulatory authority. An end-use load under a retail rate can only benefit from curtailing when the prices go up, or from using more energy when the prices go down, if the retail tariffs established by the local regulatory authority provide an option for hourly interval pricing, which allows the load-serving entity to pass through some type of charge or credit in addition to the bundled customer's retail rate.

Comprehensive Market Design Proposal. The CAISO intends to provide maximum flexibility in attempting to integrate MSS into the MD02 structure. For each of the elements of the CAISO's proposed comprehensive market design, MSS operators have the option of being treated like any other Market Participant. However, to the extent that the MSS Operator wants treatment that recognizes its unique features and functions, the CAISO proposes to accommodate MSS operators accordingly.[141] For example, MSS units will not be subject to the Must Offer Obligation. Further, MSS operators will make an annual election either to opt-in or opt-out of RUC with respect to their load. The CAISO intends to respect the existing MSS Agreements between the CAISO and the Northern California Power Authority, City of Roseville and Silicon Valley Power that were approved in connection with the Commission's approval of CAISO Tariff Amendment No. 46.[142] Finally, a MSS Operator also may elect to accept the special treatment proposed for one element of the MD02 design and not another, where it is logically consistent and practically feasible to do so.

### K. Monitoring Activities Subsequent To Implementation Of The New Market Design

#### 1. Ongoing Evaluation Of The CAISO's Market Design And Mitigation Measures

At the June 6, 2003, meeting of the CAISO's Board of Governors, a representative of Sempra Energy requested that the MSC and the CAISO's DMA organize and lead a public discussion to examine further the impact of the MD02 market design elements on prices in California under a LMP pricing regime after the design has been implemented and operating for some period of time. Sempra also urged the CAISO to adopt state-of-the art market power mitigation and monitoring policies designed to complement the new market design. The CAISO's Board of Governors requested that CAISO management and Staff consider Sempra's proposal. The CAISO believes the proposed market design already incorporates state-of-the-art market power mitigation provisions and is the best design for California. However, once LMP is implemented, the CAISO is committed to continuously evaluating market performance under the new design with particular focus on: (1) the performance of RUC, such as RUC's impact on Day-Ahead bidding and scheduling practices, effectiveness of RUC availability payment, and RUC over or under-procurement, (2) the effectiveness of the market power mitigation provisions, and (3) whether forward energy markets are sufficiently workably competitive to a level that would accommodate virtual bidding. As the CAISO gains experience under the new design and identifies potential problems or areas for improvement, the CAISO will seek the necessary design modifications from the Commission.

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[141] A MSS Operator is the entity that operates the Metered Subsystem.

[142] Tariff Amendment No. 46 involved revisions to the CAISO Tariff to accommodate MSS operators.

### 2. Virtual Bidding

Virtual bidding involves the submission of bids to buy or sell energy in the forward market that will not ultimately be produced or consumed by the bidder in Real-Time. Virtual supply bidding involves selling energy at a particular location in the forward market without a physical resource to back the transaction. Virtual demand bidding involves buying energy in the forward market at a particular location without a physical load that will actually consume the energy in Real-Time. It is essentially a speculative mechanism for arbitraging potential inter-temporal price differences (*e.g.* between the Day-Ahead and Hour-Ahead markets or between the Day-Ahead and Real-Time market). Stated differently, a "virtual bid" is any bid where there is no intent – or capability - for physical delivery or consumption. In theory, virtual bidding is a beneficial instrument for facilitating price equilibrium across inter-temporal markets. The issue of whether the CAISO should allow virtual bidding under the new market design was raised in the IFM Working Group. One issue raised by the Working Group was whether virtual bidding should be implemented initially at the time the IFM is implemented.

For the reasons discussed below, the CAISO submits that virtual bidding should not be implemented until after sufficient experience is gained with the implementation of the IFM. To that end, the CAISO's amended Comprehensive Market Design Proposal does not include an explicit "virtual bidding" proposal *per se*. [143]

As the Commission has recognized on numerous occasions, the CAISO market has been dysfunctional and marred by numerous problems, and a stable, proven market still does not exist in California. The amended Comprehensive Market Redesign Proposal constitutes a major step toward remedying the problems that have plagued California, and the IFM represents a complete paradigm shift in the way the CAISO and market participants do business. Upon relaxation of the existing market separation rule and elimination of the balanced schedule requirement, and introduction of Day-Ahead and Hour-Ahead Energy markets, the fundamental structure of the bidding, scheduling, pricing, and settlement of the market will change. Given the electricity supply and transmission problems that have plagued California and given that the CAISO

[143] As proposed by the CAISO, forward markets would clear based on the price-elastic demand curves submitted by Scheduling Coordinators, rather than inelastic demand quantities equal to either participants' or the CAISO's forecasted load at each location. This feature makes the day-ahead market "financial" in the sense that the market clearing quantities are based on participants' financial decisions (*i.e.*, willingness to pay/sell), thereby allowing the possibility that aggregate Day-Ahead and Hour-Ahead schedules may be substantially below the CAISO's forecasted system load. However, the CAISO's proposal does not provide for the ability to submit bids from virtual resources. Unit commitment decisions by either the participant or the CAISO, as well as final Hour-Ahead schedules (as modified by any CAISO dispatch instructions), are considered physical commitments.

has not heretofore operated forward Energy markets, it may be appropriate to ensure that the forward markets are up and running properly before implementing any virtual bidding mechanism. The other successful independent system operators did not implement virtual bidding initially when they implemented their Day-Ahead markets. The Commission should not require the CAISO to do so either.[144]

Further, in no event should the Commission permit "implicit virtual bidding" – practices in which virtual bids are not explicitly labeled as such. As the Commission is well aware, implicit virtual bidding occurs today in the CAISO's markets and has created significant reliability problems for the CAISO's grid operators for several years. Simultaneously herewith, the CAISO is submitting a proposed Tariff provision that prohibits the submission of false information (thereby effectively proscribing virtual bidding) as part of its Oversight and Investigations filing. If virtual bidding is permitted, there is no legitimate reason why a bidder should object to flagging a bid as virtual unless the bidder is seeking to game the system by misrepresenting its intent. The CAISO also believes that implicit virtual bidding runs afoul of the proposed requirement in the SMD NOPR that market participants provide factually accurate information to the independent transmission provider or be subject to penalty.

At a minimum, any virtual bidding mechanism must be explicit by requiring that virtual or purely financial bids be flagged (a model commonly referred to as "explicit virtual bidding"). The CAISO notes that PJM and the New York ISO require that bidders identify virtual bids. The same requirement should apply in California in the event virtual bidding is implemented at some time in the future. This will allow the CAISO's grid operators to distinguish real (*i.e.*, physical) bids from bids that are purely financial and will be liquidated in Hour-Ahead or in Real-Time. When virtual bids are explicitly labeled as such, the CAISO can make unit commitment decisions and take other actions necessary for reliable grid operations based on the knowledge of what is real and what is virtual. In other words, if grid operators can distinguish which supplies will be available in Real-Time and which supplies are not intended to be available, they can plan accordingly. Failure to identify virtual bids clearly could cause CAISO operators to scramble unnecessarily in Real-Time when supplies that were bid in the Day-Ahead – and that the CAISO counted on being there – fail to show up. If virtual

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[144] An issue related to virtual bidding that was raised in the Working Group was whether the newly acquired software and systems to implement market redesign should accommodate "explicit virtual bidding". The CAISO believes that the new software should accommodate this functionality. The CAISO notes that the Commission's SMD NOPR contemplates the accommodation of explicit virtual bids, and the Eastern independent system operators have implemented explicit virtual bidding successfully. Under these circumstances, it would be prudent for the CAISO's new software and systems to accommodate the potential implementation of explicit virtual bidding in the future. The CAISO anticipates that it would be more cost effective and less of a burden if the new software and systems are designed initially to accommodate explicit virtual bidding than if the software/systems have to be modified at some future date.

bidding is to be permitted, it must be permitted only under a set of rules and procedures that will prevent any adverse impacts on reliable grid operations.

In conclusion, the CAISO recommends that Market Participants continue to address the issue of virtual bidding in an ongoing monitoring/stakeholder process subsequent to implementation of MD02. The CAISO will also continue assessing the merits of explicit virtual bidding (as part of the market evaluation process discussed in the prior section) and attempt to identify when it may be appropriate to allow such bidding. At such time as the CAISO determines explicit virtual bidding should be adopted, it will make a Section 205 filing to amend the Tariff accordingly.

## IV. SERVICE

The CAISO has served this filing on the Public Utilities Commission of the State of California, the California Energy Commission, the California Electricity Oversight Board, and all parties with Scheduling Coordinator Agreements under the CAISO Tariff. In addition, the CAISO has served all parties in Docket No. ER02-1656 and has posted a copy of the filing on its Home Page.

## V. NOTICES

Communications regarding this filing should be addressed to the following individuals whose names should be placed on the official service list established by the Secretary with respect to this submittal:


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## VI. SUPPORTING DOCUMENTS

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| Attachment A | Amended Comprehensive Market Redesign Proposal |
| Attachment B. | Chart of Major Changes Since the MD02 May 2002 Market Design Filing |
| Attachment C | Memorandum to ISO Board of Governors Re Comprehensive Market Design Proposal and Board of |

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| | Governors Resolution on Comprehensive Market Design Proposal |
| Attachment D | Market Surveillance Committee Opinion on the Necessity of Effective Local Market Power Mitigation for a Workably Competitive Wholesale Market |
| Attachment E | Index of Major Design Features |
| Attachment F | Market Surveillance Committee Comments on Locational Marginal Pricing and the California ISO's MD02 Proposals |
| Attachment G | Charts Showing Phantom Congestion of Heavily Utilized Paths |
| Attachment H | Notice of Filing |

## VII. CONCLUSION

Wherefore, for the reasons stated above, the CAISO respectfully requests that the Commission accept the CAISO's MD02 market design as reflected in the Proposal.

Respectfully Submitted,

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