UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	))	Docket No. ER02-1656-000
	)	
Investigation of Wholesale Rates of Public Utility Sellers of Energy and Ancillary Services in the Western Systems Coordinating Council	))))	Docket No. EL01-68-017

STATEMENT OF POSITION OF
THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Pursuant to the "Notice of Technical Conference" ("Notice") issued by the Federal Energy Regulatory Commission ("Commission") on November 8, 2002 in the captioned proceeding, the California Independent System Operator Corporation ("CAISO")[1] hereby submits its Statement of Position on the outstanding and unresolved issues.

In support hereof, the CAISO respectfully states as follows:

I. BACKGROUND

On May 1, 2002, the CAISO filed its Comprehensive Market Design proposal ("MD02 Filing") with the Commission. The CAISO proposed to implement the MD02 proposal in three phases. Phase I included, *inter alia*, market power mitigation measures designed to prevent physical and economic withholding and an interim residual unit commitment ("RUC") process. By its

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

orders issued on July 17, 2002,[2] October 11, 2002,[3] and October 25, 2002[4] the Commission has resolved the MD02 Phase I issues.

Phase II of the CAISO's MD02 Proposal included, *inter alia*, implementation of an integrated forward market ("IFM"). The Phase II IFM proposal involved elimination of the market separation rule and balanced Schedule requirement in conjunction with implementation of simultaneously optimized Congestion Management, Energy market, Ancillary Services procurement and unit commitment on a zonal basis. Phase II also contemplated that a RUC process would be in place.

Phase III provided for implementation of a full network model, redesigned firm transmission rights ("FTRs"), a resource adequacy obligation for Load Serving Entities ("LSEs"), and an integrated Congestion Management, Energy, Ancillary Services and Unit Commitment Market based on locational marginal pricing ("LMP"). In its July 17, 2002 Order, the Commission established a technical conference to address the MD02 Phases II and III proposals. The Commission did rule on the merits of the specific Phases II and III elements proposed by the CAISO. However, the Commission authorized the CAISO "to begin expending funds on the development of software and systems for LMP and the full network model." July 17 Order at ¶ 117.

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

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

4 *California Independent System Operator Corporation*, 101 ¶ 61,084 (2002).

Pursuant to the July 17, 2002 Order, the Commission Staff convened a technical conference in San Francisco on August 13-15, 2002. Given the large number, the broad scope and the significance of the unresolved issues and the likelihood that these issues cannot be addressed effectively or efficiently in large-group meetings with more than a hundred participants, the CAISO and stakeholders established four stakeholder working groups to address and resolve outstanding issues. The four working groups are:

1. Long-term Resource Adequacy-- This group has addressed, *inter alia*, issues raised in the CAISO, State Interagency Working Group, and Reliant proposals, as well as general resource adequacy issues.
2. Integrated Forward Markets-- This group has addressed the elimination of market separation and the balanced schedule requirement, integrated forward congestion management, energy market, Ancillary Services procurement and unit commitment, provisions for bilateral schedules and related issues.
3. Locational Marginal Pricing ("LMP") and Congestion Revenue Rights ("CRRs")-- This group has addressed the full network model, nodal pricing, load aggregation for settlements purposes, CRR design and allocation, treatment of Existing Transmission Contracts, and local market power mitigation in an LMP world.

4. Transitional Issues-- This group has addressed issues related to the market framework that will exist prior to the implementation of Phase II, including certain Phase I items such as real-time economic dispatch, moving the Hour-Ahead market closer to real-time and unit commitment.

The Stakeholder Working Groups have been meeting regularly since September. Although the Stakeholder Working Groups have resolved some issues, a large number of significant issues remain unresolved. By its Notice issued on November 8, 2002, the Commission scheduled a technical conference regarding the CAISO's MD02 Proposal to assess the progress of the Stakeholder Working Groups, and to facilitate continued discussions between the CAISO and stakeholders regarding the development of the remaining elements of the CAISO's proposed market redesign and to identify related implementation issues. In preparation of the technical conference, the Commission directed the MD02 Stakeholder Working Groups to file by November 25, 2002 a Stipulation of Issues identifying which issues have been resolved and any issues that remain unresolved. The Commission then directed each party to prepare a Statement of Position regarding those issues that remain open.[5] The CAISO hereby submits its Statement of Position regarding the outstanding Phase II and Phase III issues in this proceeding, as well as the CAISO's general position regarding issues associated with resource adequacy.

[5] The Commission also directed the ISO to file by December 2, 2002 its presentation referenced in the ISO's October 29, 2002 "Request For Technical Conference."

II. FRAMEWORK FOR CAISO POSITIONS AND PROCESS RECOMMENDATIONS

Over the nearly two-year period since the CAISO began to consider comprehensive redesign of its markets,[6] the primary focus has been on the CAISO's core functions, namely, non-discriminatory access to transmission service using market-based congestion management procedures, and reliable operation of the grid in Real Time using market-based procurement of ancillary services and real-time balancing energy. The same focus on core functions, combined with a whole-system design approach to ensure internal consistency of the ultimate design, provides the guiding criteria for developing the CAISO's positions described in this filing.

The focus on core functions and internal consistency led the CAISO to the conclusion, as stated in the May 1 Filing, that proper market redesign should entail the following: (1) enforcement of a full network model in both the forward congestion management procedures and in real-time dispatch, thereby eliminating the inter-zonal/intra-zonal distinction and preventing infeasible schedules; (2) using Locational Marginal Pricing ("LMP") at the nodal level to settle supply resources; (3) redesign of Firm Transmission Rights (*i.e.*,

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[6] The comprehensive redesign effort that has culminated in the MD02 project actually originated with the CAISO's Congestion Management Reform ("CMR") project that began early in 2000, following the Commission's January 2000 Order to redesign the CAISO's zonal congestion management model to eliminate the distinction between inter-zonal and intra-zonal congestion and thus prevent market participants from establishing infeasible forward schedules. *See California Independent System Operator Corporation*, 90 FERC ¶ 61,006 (2000). The CMR project culminated in the CAISO's draft CMR proposal of January 2001, which was filed with the Commission for information purposes at that time. Due to the electricity crisis that began in Summer 2000 it was not appropriate for the CAISO to follow the CMR project through to implementation, but instead to initiate a more comprehensive market redesign effort late in 2001 (i.e., MD02) that would draw upon lessons learned from the crisis and consciously address its root causes.

Congestion Revenue Rights or CRRs) to be compatible with a LMP congestion management approach; (4) simultaneous optimization of energy, congestion management, ancillary services and unit commitment in the forward markets; and (5) a residual or reliability unit commitment ("RUC") procedure to enable the CAISO to issue unit commitment instructions when participants' forward schedules do not commit adequate resources to meet forecasted real-time needs. In conjunction with these key design elements, the CAISO also proposed essential provisions for market power mitigation at both the system-wide and local level, and a capacity obligation on load-serving entities to clearly define the responsibility and create incentives for obtaining adequate supply resources to meet peak loads and reserve requirements. The CAISO continues to believe, as stated in the May 1 Filing, that these key elements will correct the flaws in the CAISO's current market design and, with the successful completion of activities now in progress at the state level, can lead to a well-functioning electricity market structure in California.

Throughout the working group process and in developing the positions stated in this filing, the CAISO has maintained a focus on the big picture, *i.e.*, on the internal consistency of the whole design and the inter-relationships of the various elements and issues. In light of previous Commission orders to avoid a piecemeal market design approach,[7] the CAISO has continually tried to assess the impacts of specific design proposals on the functioning of the whole system, and to develop its positions on the issues accordingly. Based on these same

[7] *California Independent System Operator Corporation,* 98 FERC ¶ 61,327 (2002).

considerations, the CAISO urges the Commission to read the CAISO's and other participants' positions on these issues as progress reports on a continuing process rather than as the conclusion of that process. Put another way, the Commission should not read the absence of consensus on many issues as indicative of a need for the Commission to weigh participants' positions and make decisions on the issues. The CAISO is concerned that such an approach will undermine the CAISO's diligent efforts in MD02 to maintain an integrated, comprehensive design approach. At the same time, the CAISO reasserts its commitment to give serious weight to the expressed concerns and business needs of all participants expressed through the various Working Groups and other CAISO stakeholder forums. Indeed, this filing discusses specific examples of issues for which the CAISO has agreed to modify its original MD02 position to address valid stakeholder concerns (see, for example, the discussion of load aggregation).

As a final note, the CAISO points out that the four working groups have thus far proceeded relatively independently of one another, and that to date there have not been specific working group activities aimed at integrating the issues and proposed solutions across the four groups. The CAISO will pull together the various Working Group recommendations, attempt to integrate such recommendations with a comprehensive view in mind and present an integrated recommendation to stakeholders for their review.

III. PHASE II ISSUES

A. Summary Of The CAISO's MD02 Proposal

The CAISO's forward congestion management and energy market proposal is set forth in Section 5.2 of the Comprehensive Market Design Proposal which is Attachment A of the May 1, 2002 MD02 Filing. As indicated above, Phase II would establish the integrated forward congestion management, energy, ancillary services and unit commitment market using the CAISO's existing three-zone network model.

The CAISO's proposal with respect to Ancillary Services Procurement is set forth in Section 5.4 of Attachment A to the MD02 Filing. Ancillary Services would be procured simultaneously with Energy market in the forward market. Ancillary Services resources would be selected using an opportunity cost approach based on the resource's Energy bid. The CAISO's proposal allows suppliers to submit capacity bids in addition to their Energy bid curves. Under this approach, the resource's capacity bid would be paid as an adder to the opportunity cost determined from the submitted Energy bids. The price paid to Ancillary Service awards will be the marginal cost based on the shadow price constraint. Ancillary service requirements could be determined on a system or local basis.

The CAISO's IFM proposal also contemplates a RUC process for reliability purposes after the Day-Ahead Congestion Management, Energy and Ancillary Services market has been run and has established final Day-Ahead Schedules. RUC would allow the CAISO to commit additional resources beyond those scheduled in the Day-Ahead market if needed to meet the CAISO's system load forecast. The Phases II and III RUC process is discussed in Section 5.5 of Attachment A to the MD02 Filing.

Section 5.6 of Attachment A to the MD02 Filing discusses the structure and timing of the Hour Ahead and Real Time Markets. The CAISO proposes to close the Hour-Ahead market to market participant submissions as late as 60 minutes before the start of the operating hour.

B. The CAISO's Position On Outstanding Issues

ISSUE NO. 1: Timing of the Hour-Ahead Market

In its MD02 Filing, the CAISO proposed that the Hour-Ahead market be closed 60 minutes before the beginning of the operating hour. MD02 Filing, Attachment A at 111. Closing the Hour-Ahead market at approximately T-60 (sixty minutes prior to the start of the operating hour) would combine the submission of bids for the Hour-Ahead and Supplemental energy markets and allow schedule changes closer to real time. In order for this to be workable for the CAISO, it would be necessary for the CAISO to stop accepting Supplemental Energy bids at the same time. This would allow CAISO operators to run Hour-Ahead Congestion Management and Energy and associated AMP procedures, to determine final Hour Ahead schedules based on SCs' submitted bids and schedule changes, and then to issue Imbalance Energy pre-dispatch instructions as needed from among the energy bids that were not accepted in the integrated Hour Ahead Congestion Management and Energy procedure.

The MD02 proposal as described above 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 that is near 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 allow the CAISO adequate time to run the necessary processes and procedures that it must undertake.[8]

However, the CAISO's experience running AMP over the past month suggests 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 to receive and process the Hour Ahead information by the time they get the Real Time information. Accordingly, CAISO staff are still fine tuning the CAISO's proposal and will discuss any proposed revision with stakeholders in a timely manner.

The CAISO is not opposed to allowing a slight difference between the Hour Ahead timeline and the closing of the Real-Time energy market to accommodate the processing of schedule changes for both the CAISO and market participants. The current market Hour Ahead market requires up to 20 minutes to be processed by the existing CAISO systems after the Hour Ahead market is closed to changes by market participants. Because the CAISO does

[8] The Commission should not approve any timeline that jeopardizes the CAISO's ability to perform the aforementioned functions effectively and reliably.

not have any way of knowing how long it will take to process the Hour Ahead market with its new features on a new system, the CAISO can only anticipate that it will take at least as long as it currently does. For this reason, initially it would be prudent to allow a difference in timing between the Hour Ahead and Real-Time markets. Until the CAISO gains some experience with new market features and systems and determines how long it actually takes to run the Hour Ahead sequence (and while recognizing that it may not be optimal from a pure market prospective), a difference in timing between the two markets will be required. This break would be something on the order of submitting Hour-Ahead schedule changes at 70 to 90 minutes prior to the hour, with any unused bids from the Hour-Ahead market rolling into the Real-Time Imbalance Energy market.

Some participants in the Working Groups have recently raised 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 therefore argue for the necessity of 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. Unfortunately this proposal 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.

The CAISO sees this issue as a simple choice between moving the Hour-Ahead market closer to Real Time and eliminating the current re-bid period, or retaining the re-bid period and keeping the Hour-Ahead market timeline roughly where it is today. Either option could be compatible with the comprehensive MD02 design. The CAISO originally proposed the first option in response to what it believed was universal support for this change. However, no consensus has been reached on this issue in the Working Group. Therefore, the CAISO is inclined to revisit its initial proposal and is open to further discussions on this issue.

ISSUE NO. 2: Virtual Bidding

The CAISO's MD02 Filing did not include an explicit "virtual bidding" proposal *per se*. 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.[9]

At the same time, the CAISO's proposal does not explicitly provide for the ability to submit bids from virtual resources (e.g., virtual loads and virtual supply

[9] While some have argued that allowing load to shift procurement between the day-ahead, hour-ahead, and real-time market is "virtual bidding", the CAISO believes it is fundamentally different in that these transactions would be settled at a single price (e.g. load that does not clear the forward markets would be settled at the Real Time price), whereas true virtual transactions settle against two prices, a position price and a liquidation price (e.g. virtual load buys in the day-ahead market and liquidates its position in the real-time market at the real-time price). Put another way, if the load and supply that are scheduled in the forward markets are actually intended by the participants to perform at least up to the level scheduled, this is not virtual bidding.

resources that are not intended by the participant to appear in real time). Moreover, the CAISO's proposal does include an explicit provision that forward 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. The CAISO believes that this provision effectively precludes virtual supply bids or schedules in the Day Ahead and Hour-Ahead markets.

The issue of virtual bidding was raised in the IFM Working Group. One issue raised by the Working Group is 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.

As the Commission has indicated on numerous occasions, the CAISO market has been dysfunctional and marred by numerous problems. A stable, proven market still does not exist in California. The MD02 Comprehensive Market Redesign constitutes a major step toward remedying the problems that have plagued California and the Phase II 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 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.

The second issue related to virtual bidding that was raised in the Working Group is 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 Standardized Market Design Notice of Proposed Rulemaking 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. 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.

The third virtual bidding issue addressed by the Working Group was whether, if explicit virtual bidding is implemented at a later date, should virtual bids be distinguished from physical bids. The Working Group reached a consensus that, if virtual bidding is implemented, virtual bids should be distinguished from physical bids. The CAISO supports the consensus position. Indeed, the concept of "explicit" virtual bidding entails explicit labeling of virtual bids as such, by definition.

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 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.

Two related issues identified by the Working Group are (1) what is the definition of a "virtual bid" and (2) what constitutes an "implicit virtual bid" and whether implicit virtual bidding should be precluded. In the CAISO's opinion, a "virtual bid" is any bid where there is no intent – and perhaps not even the capability -- for physical delivery or consumption. The CAISO believes that "implicit virtual bidding" – practices in which virtual bids are not explicitly labeled as such – should be prohibited. 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. 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.

In conclusion, the CAISO recommends that market participants continue to address this issue in a meaningful stakeholder process. The CAISO and the CAISO Market Surveillance Committee will also continue assessing the merits of explicit virtual bidding and identifying when it may be appropriate to allow such bidding. At such time that the CAISO determines explicit virtual bidding should be adopted, it will make a Section 205 filing to amend the Tariff accordingly.

ISSUE NO. 3: Accommodation of Bilateral Transactions and Other Self-Scheduling Options

The MD02 proposal will both accommodate and facilitate bilateral transactions. Under the CAISO's MD02 Congestion Management proposal, Scheduling Coordinators ("SCs") will submit Energy/Adjustment bids on their preferred generation and load schedules that will be used to clear congestion and execute economically efficient trades. However, unlike the existing congestion management mechanism where, after the congestion-related schedule adjustments each SC portfolio must be balanced separately and independently, under the MD02 congestion management mechanism, the congestion-related adjustments of schedules will be done across the entire CAISO Control Area (regardless of any individual portfolio balancing) and, thus, will provide for total CAISO Control Area optimization. As a result, balanced schedules for each SC will be an option rather than a requirement. SCs who desire to preserve the strictly bilateral nature of schedules depicting their contractual obligations or arrangements can submit schedules with load and generation balanced, accompanied either by price-taker Energy bids or no bids at all, thereby becoming price takers for congestion charges. *See* MD02 Filing, Attachment A at 82. SCs who schedule in this manner can couple their bilateral schedules with accompanying CRRs and achieve price certainty for transmission. Thus, the CAISO's proposal accommodates bilateral scheduling for those SCs that desire to schedule in this manner.

At the time the May 1 Proposal was drafted, the CAISO had not yet considered other aspects of the "bilateral scheduling" issue that have surfaced in the course of the IFM working group. The most obvious case, as stated above, is the case in which the SC wishes to self-schedule a given quantity of load to be served by its own generating resources, and to prevent this schedule from being adjusted for energy trading or for congestion management, except as a last resort when bid-based congestion management has been exhausted. The more general concept of “self-scheduling” also includes non-balanced options. For example, a supplier may wish to operate a generating plant at a specific level without regard to price and without pre-designating the load it will serve. The CAISO’s proposal allows the unit to be self-scheduled at a preferred operating level with no associated energy bids (subject, of course, to any applicable Must Offer obligation), and thereby to be a price taker in the relevant market.

The issue of self-scheduling is also important for use-limited resources, *i.e.*, resources whose primary energy source is limited (e.g., hydro), or that are under environmental constraints that limit operations. This issue is addressed explicitly in a subsequent section of this filing.

Several participants have pointed out that it may be problematic to try to accomplish self-scheduling through the use of price-taker bids in the context of the CAISO’s mitigation measures, specifically the $250 bid cap and the AMP mechanism. They argue that energy bids designed to prevent energy trading or to achieve curtailment priority for congestion management may in fact trigger the AMP mitigation mechanism, or that trying to accomplish the same ends by not submitting bids at all would violate the Must Offer obligation and cause the CAISO to insert default bids for the resource in question. Others argue that the $250 bid cap (rather than a much higher level) may be used by different market participants for a variety of purposes and thus may not provide an adequate distinction as needed for self-scheduling. These participants have requested the option to set a flag on their bids which would explicitly distinguish self-schedules from other bidding practices that could trigger mitigation. The CAISO recognizes the legitimate business and operating needs contained in this issue and is working with the IFM working group participants to arrive at a suitable solution.

Finally, while some participants are content for balanced self-schedules to be treated as price takers for congestion management, others want to be able to (1) specify limit prices for congestion, 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 (based on physical congestion or nodal price differences). The CAISO has pointed out to participants that accommodating these desires would add significant complexity to the IFM design, and is therefore reluctant to try to develop accommodating mechanisms. Consistent with the earlier discussion about the CAISO's focus on key elements of market redesign, the CAISO believes it is important at this juncture to maximize the likelihood of a successful implementation of the integrated, LMP-based forward market, and design simplicity is crucial to such success. Such a focus for the initial implementation does not, however, preclude the possibility of adding enhancements as needed at a later date.

ISSUE NO. 4: Residual Unit Commitment[10]

In its MD02 Filing, the CAISO proposed a RUC mechanism 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

[10] The issue of the appropriate unit commitment mechanism and the corresponding compensation methodology also have been raised in the issues list submitted by the Transitional Issues Working Group. The CAISO's discussion of RUC is intended to address the issues raised in both the Integrated Forward Markets Working Group and the Transitional Issues Working Group.

are deemed inadequate. Under the RUC proposal, once the CAISO determines that it does not have sufficient resources committed after the close of the Day-Ahead Market to meet the next day's forecasted Load (by comparing the CAISO's load forecast to total load scheduled in the Day Ahead market), the CAISO would use the RUC process to commit additional generating capacity and would guarantee such CAISO-committed suppliers payment of their start-up and minimum load costs (net of market profits during the commitment period) incurred to commit their heretofore uncommitted resources.

The CAISO's RUC proposal is designed to strike a careful balance among the following principles and objectives: (1) ensure that enough generating capacity will be on-line and available for real time, (2) provide a reasonable capacity payment for CAISO-committed resources obligated to bid into the CAISO market and (3) provide a way for imports to offer supplies and be procured on a day-ahead basis to supplement in-state supplies. The CAISO believes that its RUC proposal provides a necessary, effective and reasonable reliability tool, and that it incorporates appropriate modifications associated with each phase of MD02 implementation, so that in the ultimate long-term design the CAISO's procurement role in the forward markets is minimized. A summary of the CAISO's long-term unit commitment proposal is set forth in Section 5.5 of Attachment A of the MD02 Filing.

As reflected in the issue list submitted by the Integrated Forward Markets Working Group, the stakeholders agree that the CAISO should have a unit commitment process. The CAISO hereby sets forth its reasons why the Commission should approve the CAISO's long-term RUC proposal.

Previously, the Commission has indicated that the CAISO does not need RUC because the Commission has approved the Must-Offer obligation. However, RUC and the Must-Offer Obligation are not substitutes for each other; they are complementary. The CAISO notes that the Must Offer Obligation is an obligation for Generators with Participating Generator Agreements as well as Generators outside the CAISO Control Area who participate in CAISO markets or use the CAISO Controlled Grid, with the exception of hydroelectric Generators, to make available to the CAISO, in real time, all of their available (or otherwise uncommitted) capacity.[11] All such Generators must offer available capacity that is not (1) on an outage; (2) under CAISO Dispatch, (3) already scheduled to run through bilateral arrangements. *See 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 61,355 (2001).

On the other hand, RUC is a unit commitment process designed to enable the CAISO to meet forecasted load by utilizing generating capacity that is

[11] The RUC process will accommodate voluntary three-part demand bidding (the equivalent of start-up and minimum load costs and energy bids). *See* MD02 Filing, Attachment A at 125-26. A bid for demand response would not be required to use multiple bid components, but such option would be available to bidders. Because participating loads can incur actual costs similar to start-up and minimum load costs of generators, but such costs would be difficult for the CAISO to calculate and verify, the three-part bids submitted by Participating Loads will be market-based and not require verification of actual costs. Instead, the bids submitted by loads will compete with generation for dispatch through the RUC process. In other words, the CAISO proposes to allow Curtailable Demand to bid a start-up/minimum load equivalent, namely, the Minimum Curtailment Payment. This will ensure the most comparable treatment that feasibly can be provided between load and generation resources.

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 or resource adequacy obligation.

Thus RUC is most properly thought of as a substitute for the current Must Offer Waiver procedure, and as such will provide a more orderly and efficient implementation of the Must-Offer Obligation with respect to long-start-time units.

The CAISO's proposed 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 absolutely necessity for the CAISO to perform its core, NERC-mandated function of reliable grid operation.[12] Although the CAISO's Waiver procedure, as adopted by the Commission, does take into account a Generating Unit's Minimum Down Time, including its Start-up Time,

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[12] 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 it determines that the resources scheduled day ahead will not be sufficient to meet the next day's load and reserve requirements.

it is not an effective substitute for a structured, objective and transparent unit commitment process.[13]

Finally, the RUC procedure is consistent with the Commission's proposed standardized market design and 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 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

[13] In its October 11 Order, the Commission indicated that the CAISO could make a Section 205 filing to revise the current Must Offer Waiver procedure by basing it on a Transmission Constrained Unit Commitment (TCUC) algorithm. Such a revision would render the Must Offer Waiver procedure effectively indistinguishable from the CAISO's RUC proposal. If both procedures are based on TCUC, they can be viewed as achieving the same result from different starting points. The Must Offer Waiver procedure assumes that all resources subject to a Must Offer Obligation will be available in real time unless explicitly granted a waiver by the CAISO; whereas, the RUC assumes that all long-start-time resources not self-committed in Day Ahead will be unavailable in real time unless given an explicit commitment instruction by the CAISO. In either case the TCUC is the algorithm for the CAISO to determine which waivers to grant or revoke, or which commitment instructions to issue.

performs the same function as the unit commitment procedures in PJM, NYISO and NEISO, there is no valid reason why the CAISO should not have RUC.[14]

ISSUE NO. 5: RUC Start-Up and Minimum Load Cost Compensation

As indicated above, resources not scheduled in the Day-Ahead market but committed in RUC will be guaranteed recovery of start-up and minimum load costs, net of market profits during the commitment cycle and subject to restrictions on self-scheduling and uninstructed deviations. Specifically, generators will be paid a capacity payment calculated based on variable operating costs rather than a payment for capacity and fixed costs.

The CAISO's payment scheme reflects the fact that the RUC procedure is designed to be 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 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. This responsibility is reflected in the guaranteed payment of start-up costs (which is based on the lower of a supplier's bid or cost-based data using

[14] A few parties have argued that the CAISO should rely on replacement reserves rather than RUC. Replacement reserves are not an adequate substitute for unit commitment because, other than No-Pay, there is no explicit obligation to provide the service. One 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, the Replacement Reserve has a time delay of up to 59 minutes. This is completely useless in meeting Real Time load.

start-up data provided by the supplier and a proxy figure for natural gas) and minimum load costs (which is based on the lower of a supplier's bid or cost-based data using 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 if a supplier's bid).[15] A resource's fixed costs can be recovered through its market-based Energy bids, and through contracting with a LSE to provide capacity and/or Energy.

Once a RUC-committed resource is up and running at minimum load, the resource owner may decide to capitalize on the CAISO's subsidization of its start-up and minimum load cost by seeking new opportunities to participate in the various markets. The CAISO therefore offers the RUC capacity payment as reasonable compensation for the resource owner to reserve its unloaded capacity for CAISO dispatch to serve California load. The capacity payment is in addition to guaranteed compensation for start-up and minimum load costs. In the event that the CAISO dispatches this capacity in real time – which will be in accordance with the resource's market-based energy bid as submitted to the RUC procedure – the resource earns the market clearing price in lieu of the capacity payment for the amount of energy dispatched.

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 provided in the MD02

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[15] 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).

proposal, if the actual costs are in excess of the formula-determined costs. 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." *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). Consistent with its prior decisions, the Commission should reject these claims.

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 (and subject to restrictions on self-scheduling and uninstructed deviations). However, the Commission has approved a "net-of-market" approach for PJM, NYISO and ISO New England. [16] It is axiomatic that an agency must conform to its prior practice and decisions or explain the reason for its departure from such precedent. *See United Municipal Distributor Group v. FERC,* 732 F. 2d 202,210 (D.C. 1984); *Greater Boston Television Corporation v. FCC,* 444 F.2d 841, 852 (D.C. Cir.), *cert. denied,* (1971) (agency must give

[16] 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.*

reasoned analysis for departures from prior agency practice). The Commission must conform to this mandate. Specifically, consistent with its decisions in PJM, NYISO and ISO New England, the Commission must permit the CAISO to "net" start-up and minimum load costs in the RUC process. The generators' position contemplates that, having been paid minimum load and start-up costs, 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.

Many suppliers have objected to cost-based pricing on the grounds that sellers should submit bids for the capacity and energy portions of a RUC instruction. Some suppliers have asserted that sellers should be able to change those bids subject to seasonal or six-month limits so that bids remain competitive but are not subject to short-term price volatility.

Under the CAISO's RUC proposal, suppliers can submit market-based bids for the energy portion of their three-part bid and those energy bids can reflect opportunity cost for energy limited resources. Only the start-up and minimum load are cost-based. The Commission has approved cost-based pricing for start-up and minimum load costs in connection with the Must Offer obligation. *California Independent System Operator Corporation,* 97 FERC ¶ 61, 293 (2001). There is no is no legitimate reason why the pricing of start-up and minimum load costs should be any different under RUC. Besides, if the CAISO had not committed the resource, the resource would have been shut down and would not have earned anything.

If the CAISO were required to adopt market-based start-up and minimum load costs, resource owners should only be allowed to change those bids once every six months. Allowing resource owners to submit market-based start-up and minimum load bids on a daily basis will likely exacerbate market power problems during high load periods when the CAISO essentially needs to commit all available resources in the control area.

ISSUE NO. 6: Timing of Unit Commitment Decisions

The CAISO proposes to make its residual unit commitment decisions after the completion of the Day-Ahead market and to 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 the process that PJM follows.

Some parties have raised the issue whether the CAISO's unit commitment decisions should be included in the Day-Ahead market. Participants have 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 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 totally defeat the ability of market participants to limit their purchases in Day-Ahead and would 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, therefore, consider this to be a viable proposal.[17]

With respect to the two options for treating the minimum-load energy of RUC-committed resources, the MD02 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. In conversations with NYISO personnel the CAISO has been informed that their approach will tend to reduce Day-Ahead energy prices somewhat at some

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[17] 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.

locations, but not to increase them. This is because the additional units committed by the NYISO are long-start thermal units whose incremental energy costs tend to be lower than the costs of MW their minimum load energy replaces, but whose start-up and minimum running costs are recovered through an uplift and are not reflected in LMP prices.

The CAISO's preference at this juncture is to remain with the PJM approach. The CAISO does not, however, preclude further discussions with stakeholders on this point.

ISSUE NO. 7: Unit Commitment And The Hour Ahead Market

An issue raised in the Working Group is "how are unit commitments made by the CAISO (*e.g.*, minimum load Energy, transmission utilization) treated in the Hour Ahead market."

When the CAISO commits a unit at minimum load in the Day Ahead RUC procedure, the relevant SC has the option of either scheduling that minimum load energy in the Hour Ahead, or allowing the CAISO to treat the energy as a Real Time pre-dispatch instruction. Submitting the resource to the Hour Ahead allows the opportunity for the resource to be dispatched above minimum load in the Hour Ahead market. In either case, however, the CAISO's guarantee of minimum load energy cost compensation will be on the same cost basis.

Regarding transmission allocation for RUC, the Day Ahead and Hour Ahead RUC procedures are based on a TCUC algorithm, which ensures that transmission capacity is available to deliver energy from committed units. The Day Ahead RUC procedure does not, under the CAISO's proposal, reserve any associated transmission capacity in Hour Ahead to prevent market participants from utilizing transmission capacity that was not scheduled in the Day Ahead market. Rather, the CAISO's proposed design is to refrain from reserving transmission capacity to allow maximum opportunity for SCs to bring additional supply into the Hour Ahead market if needed. For this reason, the CAISO estimates expected Hour Ahead schedules on the interties as an input to the Day Ahead RUC. The CAISO therefore believes that the probable impact of Hour Ahead schedule changes on transmission usage will not be significant enough to undermine the Day Ahead RUC commitment.

The CAISO will need to perform an Hour Ahead RUC procedure to review unit commitments in the Hour Ahead.[18] For example, the CAISO may commit a unit in the Day Ahead in a transmission constrained area. During the Hour Ahead market, if an increase in load leads to more generation coming into the area and exacerbating the condition, the Hour Ahead RUC may commit an additional resource to mitigate the condition.

ISSUE NO. 8: Ancillary Services

The Working Group has raised the following issue regarding the bidding structure for Ancillary Service: whether the CAISO should permit one capacity bid

[18] Not all units committed in the Day Ahead RUC process will be notified and committed in the Day Ahead time frame. Only the RUC-committed units with long start time requirements will be dispatched Day-Ahead at minimum load for (certain hours of) the following day. The five-hour window for the Hour Ahead RUC will account for updated load forecast and self-committed capacity to re-evaluate the need for the shorter start-up time units, and to revise the Day-Ahead RUC results if necessary. For example, a short start-up time unit that was committed in the Day Ahead RUC, but not dispatched at minimum load by the CAISO, may ultimately not be committed in the Hour Ahead RUC. In addition, for a unit committed in the Day Ahead RUC and dispatched at minimum load for (certain hours of) the next day, if the Hour Ahead RUC shows that the unit is not needed, then the Day Ahead RUC commitment may be cancelled by the CAISO if sufficient lead time exists such that the start-up of the unit has not commenced.

or four capacity bids. The CAISO's proposal regarding the Ancillary Services markets is set forth in Section 5.4 of the Comprehensive Market Design proposal. In its MD02 Filing, the CAISO proposed four capacity bids, one for each type of Ancillary Service. 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 differently. Finally, because Ancillary Services bids include only two figures, MW and $/MW, submitting a separate bid for each service is not a burden on the CAISO.

ISSUE NO. 9: Energy Limited Resources Issues

Several issues have been raised regarding the participation of energy limited resources in the CAISO markets. These issues include: (1) what are the criteria for energy limited resources to qualify for the energy-limited resource bid stack; (2) under what conditions should the CAISO be permitted to use energy limited resources; (3) how will the energy-limited resources be compensated if they are selected in the CAISO's unit commitment after the Day-Ahead market; (4) whether the CAISO will have an energy-limited resource bid stack to provide a mechanism for the CAISO to identify, commit and dispatch use-limited resources that are not bid into/scheduled in the Day Ahead market; (5) whether the energy limited resource bid stack will be ordered by a hierarchy of operating and availability constraints; and (6) whether resources must pre-qualify to be listed in the energy-limited resource bid stack.

The specific issues stated above require some explanation regarding the fundamental underlying problems. First, if a resource is limited in its ability to provide energy (*e.g.*, due to primary fuel limitations such as water supply, or environmental constraints such as emissions limits or water management responsibilities) and is subject to a Must Offer obligation (under the current Commission-approved rules or a subsequent resource adequacy provision), an issue can arise as to how the unit can fulfill its Must Offer obligation without violating its use limitations. The CAISO has discussed with participants the idea that the resource operator would be responsible for creating and providing the CAISO with an operating plan for the resource that reflects the expected use limitations for periods beyond a single day (*e.g.*, a month, season, or entire year). Based on that plan, the SC for the resource would provide daily MWh availability to the CAISO's Day-Ahead market, and the IFM algorithm would optimize the use of the resource over the 24 hours of the next operating day. In this way, the resource would be in compliance with Must Offer as long as its daily submissions were consistent with its operating plan. Most participants seemed comfortable with this approach. However, the question of how to validate the use limitations and the longer-term operating plans has not yet been addressed.

Second, given the existing and proposed bid-mitigation procedures, there is a question regarding the mechanisms that the CAISO will provide for operators of use-limited resources to manage their use limitations without relying on extremely high bids that may trigger mitigation or skew the reference price calculations. This is not a problem in the case described above, where the resource operator provides a daily MWh quantity to be scheduled over a 24-hour period. In that case, the resource's energy bids can be used by the IFM algorithm. However, the issue arises in instances where a resource desires to provide reserves for the entire 24-hour period while minimizing its energy dispatch by limiting dispatch to only contingency conditions. Under the CAISO's current rules, such units can submit a "contingency only" flag associated with awarded Ancillary Services capacity, so that the CAISO would dispatch all non-flagged imbalance energy bids before resorting to the flagged bids. The CAISO proposes to continue the use of such a flag under the MD02 design. An open question remains as to whether there is additional need for a more general use-limited resource "bucket" for all qualifying resources (i.e., not limited to AS providers), which the CAISO would dispatch based on non-economic criteria, only after all resources with energy bids were exhausted.

Third, assuming mechanisms are created to address the first two problems, the next step would be to determine the criteria that would be applied to determine whether a resource qualifies for the energy-limited resource bid stack. This is essentially issue number one above. This question is more complicated than the previous two because it requires more than simply creating appropriate mechanisms; rather, it is a matter of policy. The difficulty is how to define "legitimate" use limitations and distinguish them from purely economic preferences of resource operators. The CAISO and the participants seem to agree that the use-limited category should be narrowly defined and admit a very small set of resources. At this time, however, the exact specification remains to be developed.[19]

Fourth, the CAISO submits that it should be able to use energy-limited resources under any of the following circumstances: (1) in accordance with the monthly, seasonal or annual plan submitted by Must-Offer units; or (2) in accordance with the Day Ahead energy-limited bid; (3) in emergency situations;[20] or (4) under any conditions the Commission allows the CAISO to use such energy-limited resource. Energy limited resources selected under RUC will be compensated just like all other resources that are committed. Some participants have proposed that the CAISO compensate in kind, *i.e.*, provide a commensurate quantity of energy to the operator of the use-limited resource when needed at another time – rather than pay in dollars for using the resource beyond its limitations. All of these issues are still under discussion and consideration by the CAISO in the broader context of overall market design and efficiency. It has been the experience of the CAISO that carving out many specific classes for resources and differently situated market participants adds complexity to the design and has a tendency to create other unintended consequences that are detrimental to a robust market.

With respect to sub-issue no. 4 above, under the Must Offer Obligation, energy limited resources should be bid into the market in Real Time if they are

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[19] Energy output limitations may be imposed by hydro conditions, emissions allowances or other regulatory or contractual reasons.

[20] There may be circumstances such as system emergencies or contingencies in which the CAISO will need – and should be able – to dispatch energy-limited resources. The CAISO and participants seem to agree that all resources, even use-limited resources, should be available under emergency or contingency conditions.

not scheduled in the Day Ahead or Hour Ahead. A separate bid stack would lead the CAISO back in the direction of different and separate products – something that the CAISO has eliminated with the new market design. The CAISO has made significant accommodations with respect to energy limited resources in designing the Real Time market, and they are treated fairly with respect to uninstructed deviation penalties. Nothing more should be required. With respect to sub-issue no. 5, the CAISO submits that energy limited resources should be optimized pursuant to a hierarchy of operating and availability constraints for reliability purposes. Finally, the CAISO believes that resources should pre-qualify to be listed in the energy limited resource bid stack.

ISSUE NO. 10: Bid Limitations Between Sequential Markets

The Working Group issue list raises the issue of whether there should be any bid limitations between sequential markets (Day-Ahead to Hour-Ahead to Real-Time). Under the CAISO's proposal, the portion of the energy bid curve associated with capacity selected in the day-ahead market and the RUC process cannot be increased in a subsequent market. However, participants are free to revise the portion of their energy curve associated with capacity not selected in the day-ahead market and the RUC process so long as such revisions maintain a monotonically increasing energy bid curve for the unit's entire output range. MD02 May 1 Filing, Attachment A at 112; Attachment H at Section 5.13.2.2. The CAISO's proposal is consistent with the bidding limitations in place in the Eastern ISOs.

Logically this approach is analogous to the basic tenet of contract law that an accepted offer is a contract. If the CAISO is relying on an energy bid to serve scheduled load and operate the grid reliably, suppliers should not be permitted to change bids without a valid reason, thereby forcing the CAISO to scramble to meet its obligations and maintain operational integrity of the transmission system.

The CAISO's proposal also is necessary to prevent bidders from exercising market power. For example, absent this provision, a supplier could submit a low energy bid curve in order to have its unit committed in the CAISO's residual unit commitment process and then once selected, ratchet its energy bids upwards for dispatch in the real-time market. The Commission has recognized in the SMD NOPR that bidding limits may be imposed to mitigate market power. SMD NOPR at ¶ 273.

The CAISO's proposal still permits a fair amount of flexibility for suppliers. For example, in the day-ahead market, suppliers are permitted to submit different bids for different hours of the day. Further, any capacity that has been bid, but not accepted by the 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.

ISSUE NO. 11: Imports Setting the MCP[21]

The issue has been raised in the Working Group whether resources that are dispatched on a one-hour basis, *e.g.*, imports should be permitted to set the market clearing price. The CAISO notes that in its October 11, 2002 Order, the Commission ruled that imports must bid $0/MWH and be price takers. October 11 Order at ¶ 20.Further, imports would not be permitted to set the MCP and they would not be subject to the automatic mitigation procedures ("AMP").

The CAISO believes that it is important that the CAISO have market rules in place that encourage the participation of imports in California's markets. In its "Request for Rehearing and Motion for Clarification" filed in the captioned proceeding on November 8, 2002, the CAISO requested that the Commission remove the $0/MWh bid requirement for imports.[22] As an alternative, the CAISO proposed that imports should be permitted to submit bids greater that $0/MWh; however, they would remain price takers and could not set the MCP (and would not be subject to AMP). The CAISO believes that the Commission should approve this proposal in order to encourage imports to participate in the CAISO's markets. In that regard, if imports are permitted to bid prices other than $0/MWh, they are more likely to be paid an MCP that is closer to their bid price than if they are required to bid $0/MWh because the CAISO will consider their bid price in dispatching resources in economic merit order.

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21 The issue of the treatment of imported power also has been identified in the issues list submitted by the Transitional Issues Working Group. The CAISO's response is intended to address to issues raised in both Working Groups.

22 The arguments raised in the CAISO's request for rehearing regarding the need to eliminate the $0/MWh bidding requirement for imports are incorporated herein by reference.

The CAISO is concerned that if imports are permitted to set the MCP, opportunities for “megawatt laundering” will arise. The “megawatt laundering” concern is the reason why the Commission has not permitted imports to set the MCP. Indeed, in at least three orders issued in the past year – the December 19, 2001[23] and May 15, 2002[24] orders in Docket Nos. EL00-95, *et al.* and the October 11 Order herein – the Commission has recognized that preventing “megawatt laundering” is an important goal. Consistent with these decisions, the Commission should continue the requirement that imports cannot set the MCP. In the event the Commission permits imports to set the MCP, it is imperative that the Commission also subject imports to AMP. That would be the only means of limiting – but not eradicating – “megawatt laundering”. The CAISO believes that the position set forth in its November 8 request for rehearing is the approach that best balances the objectives of (1) encouraging import participation in CAISO markets and (2) preventing “megawatt laundering”.

ISSUE NO 12: Role of DEC Bids in the Hour Ahead Market

The final issue raised in the issue list submitted by the Integrated Forward Market Working Group is the role of DEC bids in the Hour Ahead market (given that the Hour Ahead market is incremental to the Day Ahead market).

Decremental bids in any market are important to reduce the overall coast of operation by providing for efficient economic dispatch of the grid. It would be

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[23] *San Diego Gas & Electric Company vs. Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator and California Power Exchange,* 97 FERC ¶ 61,275 (2001).

[24] *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,* 99 FERC ¶ 61,160 (2002).

expected that market participants would be looking for more cost effective ways to meet their obligations and would find it beneficial to submit decremental bids. The market design as proposed by the CAISO allows for the clearing of unbalanced load and resources in the Hour Ahead market, within known transmission constraints.

IV. PHASE III ISSUES

A. Summary Of The CAISO's Phase III Proposal

Phase III of the CAISO's MD02 proposal involves implementation of the full network model, redesigned CRRs and integrated Congestion management, Energy and Ancillary Services based on LMP. The Congestion management and Energy market elements of Phase III are discussed in Section 5.2 of the Comprehensive Market Design Proposal. The CAISO's proposal regarding CRRs is set forth in Section 5.3 of the Comprehensive Market Design Proposal and Section 9 of the Tariff language filed on June 17, 2002. The CAISO proposes to allocate CRRs to Load Serving Entities ("LSEs") based on historic quantities and geographic distribution of their loads and supply resources. These CRRs will be "Oblgations". The CAISO proposed to allocate CRRs based on three different term lengths – three-year, one-year and monthly. Parties with Existing Transmission Contracts ("ETCs") that convert to CRRs will have will have the choice of receiving CRR "Obligations" or CRR "Options".

B. LMP Issues

ISSUE NO. 1: Should Locational Marginal Prices Be Used For Settlement With Supply Resources ?

The CAISO proposes to settle with generators and other supply resources such as participating loads based on nodal prices. This is a fundamental requirement of congestion management reform in the sense that it is crucial to eliminating the troublesome 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 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 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. The CAISO notes that the eastern ISOs that employ LMP settle generation at the nodal level, and that the SMD NOPR also contemplates that generation would be settled at the nodal level.

However, LMP does not eliminate the need for effective local market power mitigation. Local market power mitigation is required regardless of whether or not the CAISO settles supply resources at nodal prices. As long as the bids of supply resources are appropriately mitigated under conditions where local market power can be exercised, and the mitigated bids are used to calculate the nodal LMP prices, these nodal prices will provide the correct basis for settlement. The CAISO notes that the eastern independent system operators that employ LMP have effective bid mitigation that applies when resources are needed for local reliability, to relieve local constraints or are otherwise situated to exercise local market power.

ISSUE NO. 2: Should The Locational Marginal Pricing Default Settlement For Loads Be An Aggregation?

In its MD02 Filing, the CAISO proposed initially to schedule and settle loads at the Demand Zone level and, when technically feasible, at the Load Group level. The MD02 Filing contemplated approximately 20 Demand Zones in the CAISO Control Area and over 40 Load Groups. Numerous parties have expressed anxiety that LMP pricing will have a significant negative cost impact on them. The CAISO has consistently recognized the equity concerns of these parties and is willing to accommodate such concerns. Specifically, in response to these concerns, the CAISO believes that it is appropriate to establish default load aggregation groups at a high level, at least for a transition period. This high level aggregation would have four distinct pricing areas for load settlement: the current NP15 and ZP26 zones; and the Southern California Edison Company and San Diego Gas & Electric Company transmission service territories (which today comprise the SP15 zone). All LSEs within these boundaries – including municipal utilities and non-utility retail service providers – would schedule loads at this level and would settle those loads at load-weighted average nodal prices for each of those four areas. This approach is consistent with the approach taken by PJM and the NYISO, both of which settle loads at a high level of aggregation. This approach would address the concerns of parties regarding LMP cost impacts on loads without sacrificing the primary benefits of LMP for the California market.

The CAISO characterizes this high-level aggregation as the default load settlement in the sense that all loads within the CAISO control area would settle at this level unless they choose to opt out. Some parties argue 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 believes it is reasonable to consider this feature and that the LMP Working Group should address the proposal and assess its merits. The LMP Working Group should also address the issue of the appropriate aggregation levels for loads in the long-term.

ISSUE NO. 3: Should The CAISO Use An AC Optimal Power Flow Model for the Power Flow Simulation?

The CAISO proposes that Real-Time dispatch will be based on the results of an AC Optimal Power Flow ("OPF") that will minimize the Real-Time cost of imbalance Energy, determined from Energy bids submitted by participating resources, subject to transmission interface, nomogram, and resource capability constraints, while accounting for transmission losses. *See* Section 5.7.2.3 of the

Comprehensive Market Design Proposal. In general either a DC model or an AC OPF model can be used. 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, reactive power limits, and other dynamic features of the transmission network. Although an AC OPF is more complex than a DC OPF, it has numerous benefits that outweigh the complexity.

AC models can incorporate the “dynamic” features of the transmission system by observing voltage constraints and reactive power limits. An AC model calculates losses on a marginal loss rate, which tends to result in “over-collection” of loss costs. The loss characteristics of the AC-OPF increase the accuracy of dispatch of resources by calculating the effects of losses on congestion in the network. Another advantage of the AC model is that other dynamic voltage and stability constraints can be incorporated via operating nomogram constraints in AC-OPF models.

The cost of transmission losses can be recovered using either marginal losses or average losses. 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 since generators do not have to guess the losses. Using marginal losses will further promote a more efficient use of the transmission system because marginal losses are included in the congestion solution rather than just being “tacked on” after the fact.

In summary, charging marginal losses will collect surplus revenue that must be returned to transmission customers. The CAISO in its June 17, 2002 Tariff filing stated that the over-collection of losses will be added to the FTR (*i.e.,* CRR) Balancing Account.

The primary concerns of the group with respect to the A/C model are the allocation of losses and the complexity of the model. The need to develop financial settlements is a concern to many parties. Others are concerned that averaging losses will not truly reflect the losses and costs of certain generators and loads. The CAISO is following the NYISO in this respect.

ISSUE NO. 4: Should There Be A Period For Testing And Implementation of LMP?

Several parties have 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 want adequate time set aside for testing and market simulation. Parties also argue that without real price impacts, they will be unable to assess the actual impacts of LMP implementation.

The CAISO has established a Project Management Office (“PMO”) to oversee MD02 implementation. The PMO has developed “ 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 commercially acceptable Systems Development Life Cycle. There are four steps for implementation of each of the MD02 phases – Initiation, Elaboration, Construction and Implementation.

The PMO has developed a Phase III project plan that follows these four steps. The CAISO will discuss this plan in greater detail at the December 9, 2002 technical conference. The Phase III project plan involves a rational systems change process 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, testing is included in the Construction stage. The testing phase includes systems, integration, end-to-end, load and performance and user access 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 approximately six-to-nine months of systems integration and market testing (including publication of the LMPs that might be created under test conditions) will be necessary for Phase III. Three-to-six months of market testing[25] should allow all market participants to become familiar with the results that a LMP scheme will produce.[26]

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[25] The six months of testing with market participation will partially overlap the 12 months of system development, so that the new design can go into operation in second quarter of 2004.

[26] 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.

In any event, if LMPs are aggregated at a high level, participants will be protected from potential localized LMP spikes. Throughout the implementation process, the CAISO has been and will continue providing Market Participants with empirical pricing analyses.[27] For the present, however, and 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.

A remaining question about the cost impact of LMP is whether the price variation that occurs under the LMP model could somehow result in higher average costs to consumers. The CAISO believes that, other 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

[27] The CAISO released an initial simulation study in September 2002 and has a follow-up in preparation for release in the near future.

instructions. As noted in an earlier section, as long as the CAISO has effective mitigation for 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.

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 both the CAISO and market participants is necessary. The CAISO's project plan includes CAISO testing and joint CAISO-market testing (*i.e.* market simulation).[28] The CAISO submits that its timeline for testing is reasonable given the extensive scope and complexity of the changes.

The CAISO submits that proper testing is both necessary and appropriate. The CAISO should not be required to rush to implement a new market design without the proper testing and analysis. The CAISO's existing market design has not functioned well. 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 New York approximately two years to implement nodal pricing. The CAISO's timetable is quite reasonable in comparison, especially given the extent of prior market design related

[28] CAISO testing includes integration testing, technical testing, and acceptance testing. The purpose of CAISO testing is to ensure that the delivered product matches the specifications.

problems in California following the break-neck implementation timetable leading to CAISO start-up.

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. Given that the current market design has several recognized flaws, it is imperative that the new market design be implemented without unnecessary delay.

ISSUE NO. 5: What Type Of Local Market Power Mitigation Should Apply Under LMP?

Numerous parties have raised the issue of the appropriate local market power mitigation measures that should be in-place when LMP is implemented. The various options that have been discussed by the Working Group include (1) the approach proposed by the CAISO which is similar to the methodology that the Commission approved for PJM, (2) the methodology in place in the NYISO, and (3) the methodology in place in ISO New England. 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 or (2) a level based on cost plus a 10 percent adder. *Atlantic City Electric Company, et al.*, 86 FERC ¶ 61,248 at 61,899 (1999). In ISO New England, units running out of economic merit order are subject to a screen price ranging from five to fifty percent above the reference price. If the reference price, multiplied by the screening percentage is less than the current day or hour out-of-merit bid, and the market structure screen identifies fewer than three total competitors, mitigation pricing will apply. *See* Section 17.3.2.2 and

Appendix 17-A of NEPOOL's Market Rules and Procedures. The NYISO sets In-City load pocket conduct and impact thresholds according to a formula[29] that is proportional to the number of congested hours experienced over the preceding 12-month period. The In-City bid will be mitigated if it exceeds the reference level by more than two percent.[30] *New York Independent System Operator, Inc.,* 99 FERC ¶ 61,246 at 62,046 (2002).

The CAISO submits that implementation of LMP will require corresponding implementation of adequate mitigation measures to prevent the exercise of local market power in areas of the transmission grid or across transmission pathways where there is not a competitive supply of bids. The CAISO's proposed methodology for local market power mitigation once the full network model is implemented is set forth in Section 5.9 of the Comprehensive Market Design Proposal. The CAISO proposes to apply local market power mitigation measures anytime the CAISO has to dispatch resources in the Day-Ahead, Hour-Ahead or Real-Time markets out of merit. In such cases, resources will be subject to unit-specific bid caps that will be 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 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 competitive region prices during the previous 90 days when the

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

[30] 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.

resource was dispatched in economic merit order; or (3) a negotiated price. As indicated above, the CAISO's proposal is comparable to the local market power mitigation measures that the Commission has approved for PJM. *See Atlantic City Electric Company, et al.*, 86 FERC ¶ 61,248 at 61,899 (1999).

The CAISO is amenable to discussing alternative local market power mitigation measures with stakeholders, including those approved for the New York Independent System Operator and ISO New England. In any event, it is imperative that adequate local market power mitigation measures be in-place when LMP is implemented. The CAISO notes that in its "Comments on Mitigating Local Market Power and Interim Measures for Intra-Zonal Congestion Management" filed with the Commission of September 12, 2002, the CAISO's Market Surveillance Committee indicated that stricter local market power mitigation measures are needed in California, and the measures approved by the Commission in its July 17, 2002 order herein are wholly inadequate. Accordingly, the Commission should make it a priority to approve effective local market power mitigation measures prior to and in conjunction with implementation of LMP. The local market power mitigation measures employed by PJM have work effectively and thus would serve as the CAISO's default proposal for California in the event the stakeholder process does not bring forward a superior mitigation approach.

C. CRR ISSUES

The Working Group has identified 20 outstanding issues related to CRRs. The CAISO has developed internal positions on many of these issues. Most of these positions are reflected in the May 1 Filing and the Tariff language filed on June 17, 2002. The CAISO's position on these issues is set forth in Section IV.C.2. However, due to time constraints and the press of other matters, there are a number of outstanding issues on which the CAISO has not yet developed an internal position and/or is reconsidering its filed position. These issues are identified in Section IV.C.1. The CAISO is committed to addressing and developing an internal position on these issues as soon as possible.

1. Unresolved Issues

The CAISO has not developed a final internal position on the following issues identified by the CRR Sub-Group:

- Issue No. 3—Quantity of Load Eligible for CRR Allocation
- Issue No. 4.—On-Peak vs. Off-Peak and Seasonal CRRs
- Issue No. 5—Reference Period for CRR Allocations
- Issue No. 6—Definition of Entity Entitled to CRR Allocations
- Issue No. 9—Expiration of CRRs Midway Through a CRR Term
- Issue No. 10—Exchange Contracts with Delivery Outside of the CAISO
- Issue No. 11—CERS Contract Issues
- Issue No. 13—Load Metric for Load Duration Curve
- Issue No. 14—Use of Nomogram in Allocations and Auctions

- Issue No. 15—Load that is in Control Area but Off the Grid. Where is the Sink?

- Issue No. 19-- What Are the Criteria for a Scheduled Outage with Regard to Modeling Monthly CRRs

2. CAISO Position On Outstanding Issues

<u>ISSUE NO. 1: Rolling CRRs</u>

In its MD02 Filing, the CAISO proposed to offer a portion of the available transmission capacity ("ATC") as long-term (three-year) CRRs once every three years. In the off years, only annual and monthly CRRs would be available for remaining capacity. The CAISO recognizes that this proposal could make it difficult for a market participant to obtain a long-term hedge, if desired, anytime between the three-year allocation/auction cycles. Other options include offering only a portion of the total allowable long-term CRRs annually, or offering the full amount of allowable long-term CRRs for the third year annually. The CAISO believes that the concept of rolling CRRs has some merit.

The CAISO is amenable to offering rolling CRRs and will continue to discuss this matter with stakeholders. One option is to eliminate three-year CRRs *per se* and, instead, offer one-year CRRs that are available up to three years in the future. Under this option, participants desiring three-year CRRs could obtain one-year CRRs for each year of a three-year period, up to a total of 25 percent of ATC for the third year. Specifically, the CAISO's initial CRR allocation/auction prior to LMP implementation would offer annual CRRs for 75 percent of ATC in year one, 50 percent of ATC in year two and 25 percent in year three. In the second and subsequent annual offerings, the CAISO would offer annual CRRs for 25 percent of ATC for each of the next three years. In the event the full amount of CRRs offered in a previous year were not fully subscribed, the CAISO would offer any remaining CRRs up to a maximum total amount of 75 percent of ATC for the coming year and 50 percent for the following year. Under this approach, there would not be any CRRs with three-year terms, only one-year and one-month terms. However, the CAISO is flexible on this issue and is willing to consider other rolling CRR products.

ISSUE NO. 2: Balancing Account

The CAISO has proposed to create a single CRR balancing account for surplus/deficit CRR revenues for all PTOs. Some parties have taken the position that the CAISO should establish a separate balancing account for each PTO. Other parties, including the CRR Subgroup of the LMP Working Group, have generally supported the CAISO's proposal.

The CAISO submits that the Commission should adopt the CAISO's position for a number of reasons. First, the Working Group consensus was that having a separate Balancing Account for each PTO does not provide strong enough incentives for PTOs to maintain their transmission system. The group felt that PTOs should be encouraged to minimize outages that are within their control, but a Separate Balancing Account should not be the means to achieve that objective. Second, many transmission de-rates are not within the control of the PTOs. Third, the Working Group believed that the probability of CRR owners obtaining a better hedge is greater with a single Balancing Account than with multiple accounts. Fourth, a separate Balancing Account would be difficult to implement and would be subject to protracted disputes among PTOs because the determination of causality would be difficult to establish. Finally, one Balancing Account is more in line with the long-term goal of a single Transmission Access Charge across all PTO territories.

ISSUE NO. 3: Term of CRRs During Initial Start Up Period

In its MD02 Filing, the CAISO proposed to allocate CRRs for up to three years. Under the CAISO's filed proposal, there would be both one-year and three-year allocations. Parties have claimed that there will be uncertainty moving from a zonal scheme to LMP. These parties question whether there should be three-year CRRs at this time. Further, some parties point out that there are contracts longer than three years and cannot be fully hedged under the CAISO's proposal. Parties have offered the following alternatives to the CAISO's proposal: (1) offer only one-year CRRs initially; and (2) offer one, three and five year CRRs initially.

As indicated in the CAISO's response to CRR Issue No. 1, the CAISO is wiling to offer rolling CRRs and will continue to discuss this issue with stakeholders. One option is to eliminate three-year CRRs *per se* and, instead, offer one-year CRRs that are available up to three years in the future, as described in detail above. This should address the concerns of parties that do not want the CAISO to offer three-year CRRs at all. If participants do not want long-term CRRs initially due to uncertainty regarding the new market design, they will not have to buy the second-year or third-year CRRs, and the full 75 percent of ATC for each year's CRRs will be available to be allocated or auctioned annually.

With respect to certain parties' desire for even longer-term CRRs (*e.g.*, five-year CRRs), the CAISO believes that it is prudent to limit CRR availability to the proposed three-year period, at least initially, until the CAISO and market participants gain experience with LMP in California. The CAISO is willing to revisit this issue in the future.

<u>ISSUE NO. 4: Options vs. Obligations</u>

The CAISO proposes allocating Obligation CRRs to LSEs[31] and to offer Option CRRs to ETC rights holders who convert. Parties have raised the following alternatives to the CAISO's proposal: (1) allocate only Options to LSEs; (2) permit LSEs to request their mix of Options and Obligations; and (3) not grant Options to any entity including ETC conversions.

Although the CAISO is proposing initially only to offer Obligations CRRs to LSEs, the CAISO is willing to offer Options CRRs to LSEs in the future once the CAISO determines that it is technically feasible to do so on such a large scale. The CAISO notes that the SMD NOPR does not require independent transmission providers ("ITPs") to offer Options CRRs initially, but says they should do so once Options CRRs are technically feasible and the ITP gains experience under SMD and tests the various CRR instruments. SMD NOPR at ¶

31 In this section and throughout this document, the text refers to the allocation of CRRs to load-serving entities ("LSEs"). It should be noted, however, that some issues regarding eligibility for CRR allocation remain unresolved at this time (*i.e.*, Issue Nos. 3 and 6 itemized above). Although the relevant definitions need to be crafted with care and precision, the CAISO believes that the underlying principle, as stated in the MD02 Filing, is that the entitlement to CRRs applies to the loads (*i.e.*, end-users) themselves, and LSEs simply function as intermediaries on behalf of the loads.

248. The CAISO proposed to allocate Options CRRs only to converting ETC holders, if desired. Although this complicates the release of CRRs by requiring a distinct allocation procedure and creating different “flavors” of CRRs, and may decrease the total amount of transmission capacity available to the market, the CAISO recognizes the value of encouraging ETC holders to convert to CRRs and has determined that it will be technically feasible to grant Options CRRs on this limited basis. This is consistent with the position enunciated in the SMD Working Paper that “existing firm point-to-point transmission contracts are similar to transmission rights that are options.” SMD Working Paper, *slip op.* at 11; *see also* SMD NOPR at ¶ 245 (existing point-to-point contracts are like Options CRRs).

ISSUE NO. 5: Timeline, Implementation, Testing & Evaluation (CRR Allocation Auction)

Certain parties have raised the issue whether the CAISO should evaluate the results of the CRR allocation prior to moving forward with LMP implementation. These parties argue that the CAISO should allocate CRRs and evaluate the results. These parties contend that, if the results are not satisfactory, the CAISO should redesign the allocation method and reallocate CRRs. They argue that the CAISO should not move forward with LMP implementation until a CRR allocation has consensus support from all LSEs.

The CAISO is evaluating CRRs in conjunction with its implementation of LMP. As indicated above, the CAISO will conduct extensive testing and evaluation of the new market design. If there are flaws, the CAISO will not implement the Phase III proposal until the flaws are corrected. However, objections that individual parties may have to LMP and/or CRR allocation -- absent clear design flaws -- cannot serve as the basis for delaying implementation of Phase III. The request that the CAISO not move forward with LMP implementation until LSEs reach a consensus on CRR allocation flies in the face of the fundamental premise of the Federal Power Act, *i.e.*, only the regulated utility has the right to initiate a Section 205 filing and determine the content of such Section 205 filing. *See Atlantic City Electric Company, et al. v. FERC,* 295 F. 3d 1 (D.C. Cir. 2002).

ISSUE NO. 6: Modeling of the Scheduling Priorities

The CAISO proposes to accord a scheduling priority to point-to-point ("PTP") CRRs. PTP CRRs can either be Obligations or Options. PTP CRR schedules would have the second highest scheduling priority (after ETC schedules) and, in particular, would have a scheduling priority over other price takers in the Day-Ahead Market. Options that have been identified include: (1) limit the scheduling priority to PTP CRRs with sources and sinks that are single nodes (rather than Load Aggregation Points or trading hubs); (2) extend scheduling priority to all CRRs (including Network Service Rights) but, in the event that pro rata adjustments are needed to clear congestion, do not keep them in balance or even attempt to keep the load distribution pattern fixed; or (3) not allow a scheduling priority for any CRR.

In the MD02 Filing, the CAISO proposes to retain its existing day-ahead scheduling priority for point-to-point CRR holders. MD02 Filing, Attachment A at90. Specifically, under Section 9.7.1 of the CAISO Tariff, point-to-point CRR holders have a scheduling priority in the day-ahead market, which means that balanced schedules submitted in the day-ahead market with the appropriate point-to-point CRRs associated will have priority against curtailment over other non-ETC schedules. This priority does not extend beyond day-ahead, however, so that CRRs not used with preferred schedules in the day-ahead market for any hour have no scheduling priority in the Hour Ahead market or in real time.

The CAISO supports Option 1 and submits that PTP CRR holders should retain their scheduling priority. The impact of the CAISO's proposed scheduling priority is quite minimal, because it only provides a tie-breaker mechanism for those situations where submitted bids are insufficient to manage congestion. Under MD02's integrated energy and congestion management approach, the same bids will be used for energy trading and for congestion management, and therefore the problem of insufficient bids – and hence the frequency of instances where scheduling priority is invoked – should be minimal. Finally, the scheduling priority previously has been approved by the Commission.[32]

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

ISSUE NO. 7: CRRs for Third- Party Transmission Expansions

Proposed Section 9.7.2 of the CAISO's Tariff sets forth the conditions under which merchant transmission would be granted CRRs. Specifically, if the owner of the facility will not earn a Commission-approved return on its investment through the CAISO's Transmission Access Charge, the merchant transmission owner will receive CRRs associated with the increased transmission capacity, as determined by the Western Electricity Coordinating Council. or appropriate party. 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 a scheduling priority and the right to congestion revenues even though other SCs' energy may flow over those facilities. In addition, the CAISO's proposal is consistent with the policy enunciated by the Commission in the SMD NOPR. In that regard, the Commission has proposed that, "if an entity pays to construct new generation or transmission facilities that add transfer capability, and the costs of the upgrade are not rolled-in, the entity would receive Congestion Revenue Rights associated with the new transfer capability." SMD NOPR at ¶ 238.

Certain parties contend that there are no specific conditions for the allocation of those CRRs to the transmission project sponsor. They argue that CRRs should be allocated to the project sponsor prior to the allocation of CRRs to LSEs. The CAISO believes that the allocation of CRRs in connection with upgraded capacity is not necessarily a straightforward task such that CRRs can be awarded in a vacuum simply for the nominal amount of new capacity without consideration of all pertinent factors. The fact that the new capacity is "piggy-backing" off of the existing capacity raises important issues that need to be considered. The parties might need to consider the extent to which a low-cost upgrade was possible only because significant cost was incurred to construct the underlying facility. For example, if a project sponsor was able to expand the capacity of a line by simply installing an inexpensive capacitor, should it be entitled to CRRs for the full amount of additional transfer capability even though the PTO spent significantly more money constructing the underlying transmission line? The project sponsor probably should not receive 100 percent of the benefits of the low-cost expansion under these circumstances. The CAISO submits that such equity issues need to be considered when determining the amount of CRRs that should be awarded in connection with upgrades. In addition, it may be appropriate to consider the network implications of the new line or upgrade in determining the amount of CRRs that should be awarded.

In developing the MD02 proposal, the CAISO anticipated that the award of CRRs to parties financing either a transmission expansion or a transmission enhancement 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, thus supporting the CAISO's Revenue Adequacy.

The award of CRRs would 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.

However, under some conditions and in some locations, grid enhancements decrease the transmission capability, thus negatively affecting the holders of previously allocated CRRs. Under these conditions, the transmission expansion could render some previously awarded CRRs infeasible in the Simultaneous Feasibility Test. This is an intractable problem that requires special attention. One way to resolve this problem is to recommend that a particular grid upgrade should result in the award of favorable CRRs for the grid-enhancing portions and also the award of counter-flow CRRs (*e.g.*, CRR obligations in the opposite direction) for grid-contracting portions. Therefore, under these conditions, the expander would be assigned sufficient CRR Obligations to restore the Simultaneous Feasibility of all previously awarded CRRs on the post-expansion grid. This approach would preserve Simultaneous Feasibility for all long-term CRRs awarded in conjunction with transmission expansion or generator interconnection along with any and all CRRs directly allocated to LSEs, CRRs sold through auctions, unconverted ETCs and the CAISO's estimate of unscheduled loop flow.

Note that some economic congestion would remain, even after an appropriate grid expansion is implemented. Therefore, the awarded CRRs would continue to have value to the investors, albeit less than the value of congestion before the expansion. And if grid usage expanded, and congestion increased, the awarded CRRs would shield the investors from the associated risks and become increasingly more valuable over time.

ISSUE NO. 8: How to Reflect Upgrades to the Transmission in the Allocation/Auction Process

The CAISO 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 in only monthly CRR quantities until sufficient history is gathered. In light of this, certain parties have suggested that new transmission capacity should be included in the calculation of CRRs based on the anticipated date 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. However, their proposal is not problem-free. For example, what happens if CRRs are granted for a project that does not come on-line in a timely manner for some reason? Similarly, what happens if 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 not just the particular line. For these reasons, the CAISO does not support this proposal.

ISSUE NO. 9: CRR Allocation To LSEs/Converted ETCs vs CRR Allocation for a Specified Transition Period Followed By a CRR Auction Involving All Market Participants

The CAISO proposes to allocate CRRs to LSEs and converted ETC rights holders. Parties have suggested several alternatives pursuant to which CRRs would be allocated during some specified transition period only, after which all CRRs would be auctioned.

The CAISO submits that the proposal to require the auction of all CRRs exalts form over substance. Under a full auction scheme, entities that are entitled to an allocation of CRRs would instead be entitled to a share of CRR auction revenues. Thus any LSE that desires to maintain its rights could bid an arbitrarily high price for the CRRs and retain their full value because all of the revenues from the auction sale would return to that LSE, *i.e*. LSEs would essentially be paying themselves. Requiring the CAISO to release all CRRs at auction would impose an additional and unnecessary administrative burden on the CAISO and the parties entitled to CRRs.

Further, the objections to the CAISO's proposal reflect a fundamental misunderstanding of the proposal. Under the MD02 Filing, CRRs belong to the load, not the LSEs.[33] MD02 Filing, Attachment A at 91, 96. If a load should switch from its existing LSE to a new supplier, then the associated CRRs would be shifted to the new supplier. Moreover, the CAISO proposes to allocate CRRs s to LSEs only in the quantities necessary to serve their load, net of local generation, based on historical patterns of load and grid usage. Based on the

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

CAISO's proposed allocation rules, there should be additional transmission capacity available in the CRR Auctions. Finally, new market entrants and the other suppliers will be able to obtain CRRs in the CRR Secondary Market. *Id* at 99. Thus, there are ample opportunities for new suppliers to obtain CRRs.

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

V. TRANSITIONAL ISSUES WORKING GROUP ISSUES

ISSUE NO. 1: Unit Commitment/Must Offer Waiver Process

The CAISO's position regarding the issue of a residual unit commitment mechanism for the long-term design is set forth *supra* in Section III.

ISSUE NO. 2: Phase II Lite

In its "Order Clarifying The California Market Redesign Implementation Schedule", issued on November 27, 2002, the Commission vacated its earlier directive that the CAISO implement Phase II Lite.

ISSUE NO. 3: Treatment of Import Power

The CAISO has addressed this issue *supra* in Section III.

VI. RESOURCE ADEQUACY ISSUES

A. Introduction

The CAISO's comments regarding resource adequacy are intended to provide broad guidance to both State and Federal policymakers regarding the development and establishment of an appropriate resource adequacy mechanism. Thus, these comments are not intended to advocate for any specific proposal, including the ACAP proposal previously submitted by the CAISO. At this time, and in recognition of the primary role and significant progress of the State of California's own efforts at developing a policy framework for resource adequacy within California, the CAISO supports further development of those State efforts before defining what, in the end, may be required with respect to a limited and appropriate resource adequacy requirement for users of the CAISO Controlled Grid.

B. Background

On May 1, 2002, as part of its Comprehensive Market Design proposal, the CAISO filed to establish an Available Capacity ("ACAP") obligation on load-serving entities in California. The ACAP obligation was intended as an integral element of the proposed new market design necessary to support the CAISO's core function *i.e.*, providing non-discriminatory and reliable transmission service to all customers. Subsequent to the CAISO's May 1 Filing, the Commission issued its SMD NOPR. One element of the SMD NPOR was a long-term resource adequacy requirement. Similar to the CAISO's ACAP proposal, the long-term resource adequacy requirement proffered by the Commission in the

SMD NOPR would establish the minimum level of planning reserves a load-serving entity must procure and identify in order to support transmission system reliability.

Perhaps more importantly, concurrent with the development of the CAISO's MD02 proposal, a number of California state agencies initiated rulemakings related to resource adequacy. Appendix A includes a brief summary of the state activities that are related to the CAISO's MD02 proposal. The progress of the State's efforts has been significant.

In its July 17 Order, the Commission directed the CAISO and stakeholders to develop, through the "technical conference" process established therein, a long-term resource adequacy proposal. On August 13-15, the Commission convened a technical conference to initiate, among other things, that process. Subsequent to the August 13-15 technical conference, the CAISO and stakeholders formed the Resource Adequacy Working Group" or "RAWG". In addition, in order to increase commitment to that process and in order to recognize the significant and legitimate role of the State in developing a consensus resource adequacy proposal, State agencies, represented by the State's "Inter-Agency Working Group" or "IAWG", were chosen to facilitate the RAWG discussions. In order to further focus the RAWG's discussions, the RAWG split into three different sub-groups:

(1) *Allowable Resources* – whose purpose is to develop principles for determining the eligibility of various types of resources to provide

capacity that could be procured by LSEs to satisfy a resource adequacy requirement;

(2) *Nature and Level of Obligation* – whose purpose is to develop principles on the nature of the resource adequacy obligation and the appropriate level of reserves.

(3) *Jurisdiction/penalties* - whose purpose is to develop a principles on the appropriate delineation of responsibilities regarding which entity oversees and monitors compliance with an established resource adequacy requirement and whether and how penalties/incentives for non-compliance/compliance should be applied.

Therefore, the position of the CAISO regarding each of the resource adequacy-related issues identified below is based on the CAISO's experience in developing its ACAP proposal and the CAISO's participation in the RAWG discussions.

C. Resource Adequacy Issues

ISSUE NO. 1: Recognition of Regulatory Constraints-- What is the Role of the Various Entities Involved in Satisfying Long-term Resource Adequacy?

One of the primary issues addressed by the CAISO and before the RAWG is whether any resource adequacy proposal is necessary in light of state or local regulatory agency actions regarding procurement rules/obligations of jurisdictional load-serving entities. If so, should such a resource adequacy be phased in over a period of time.

As stated in the CAISO's May 1 Filing, the CAISO has always recognized the legitimate role of the state in overseeing the procurement practices of state (or local) jurisdictional LSEs. The CAISO acknowledges that state and local authorities may, and probably should, establish procurement obligations that extend beyond those potentially established by the CAISO. For example, the CAISO recognizes that states may desire to establish target reserve levels that support more than just reliable transmission system operation – which is the focus of the CAISO's efforts – including efforts to support the development of renewable energy resources, state-wide fuel diversity, demand programs and other similar initiatives. It was never the CAISO's intention to establish rules that would conflict with such state/local-established requirements. Rather, as outlined in the May 1 Filing, the CAISO's ACAP proposal was principally focused on establishing the *minimum* requirement necessary to support reliable system operation. Thus, to the extant that state or local authorities established different, but higher, standards, these standards would necessarily complement – not conflict – with the CAISO-established standards. Most importantly, the CAISO proposed to establish minimum standards that would apply to all load served off of the CAISO-controlled grid. Therefore, while individual jurisdictions could establish different (higher) standards, the CAISO could ensure that all users of the grid, regardless of jurisdiction, satisfied the requisite minimum standards; the standards necessary to support reliable system operation. The Commission's SMD NOPR has proposed a similar construct to be applied nationwide by all transmission providers. .

However, as expressed above, and in order to ensure the development of compatible and complementary resource adequacy standards, the CAISO supports deferring establishment of any CAISO-specific requirement until State efforts have been further finalized and it is affirmatively determined that a CAISO-established requirement is necessary.

ISSUE NO. 2: Placement of Obligation and Should There Be Symmetrical Obligations on Both Load and Supply

Another issue related to resource adequacy is the entity on whom the various obligations should be placed. As stated in the May 1 Filing, the CAISO continues to believe strongly that it is the obligation of all LSEs to procure sufficient resources to satisfy their anticipated peak load requirements, plus reserves. As the Commission has recognized, one of the primary causes of 2000-2001 California electricity crisis was the failure to establish (or maintain) a clear obligation for LSEs to procure, in advance of real time, sufficient capacity to satisfy their load, as well as mechanisms by which LSEs would comply with such an obligation. The CAISO, through its ACAP proposal, proposed to reestablish that obligation to procure resource capacity in advance the day-ahead market. Absent such an obligation, the CAISO is concerned that LSEsmay, to a great extent, rely on spot market purchases to satisfy their load. This is inappropriate and jeopardizes the reliable operation of the transmission system. Of course, in relying on the spot market, one *assumes* that sufficient supply resources will be available through such market at reasonable prices. As we learned during the crisis, such an assumption is dangerous. In addition, the CAISO believes that it is inappropriate for LSEs to rely on the spot market and assume that appropriate price mitigation will be in place to protect them from high prices. Therefore, an obligation on load-serving entities to procure capacity in advance of the day-ahead and real-time markets is appropriate and necessary. In the first instance, such requirements can be defined and established by local regulatory authorities.

With respect to issues of supplier obligations, the CAISO supports the concept of imposing a reporting obligation on suppliers. Under such a mechanism, suppliers would report, in aggregate numbers, the amount of capacity they have under contract (*i.e*. to LSE's in the CAISO control area) and the amount of capacity they have available for contracting. The CAISO believes that such a requirement is reasonable and is consistent with the intent and spirit of the existing "Must Offer" Obligation. It is the CAISO's understanding that Reliant has already proposed such an obligation. While the CAISO did not propose such an obligation as part of its MD02 proposal, the CAISO is amenable to including such a provision in its tariff, should the CAISO proceed with establishing a resource adequacy requirement.

Finally, with respect to supplier performance obligations and related penalties, it is the CAISO's position that such matters are best addressed in the contract between the LSE and the supplier. However, with respect to general availability requirements (*e.g.*, outage reporting) and performance obligations (*i.e.*, deviation penalties) in the CAISO's spot markets, such rules and consequences are best addressed in the CAISO Tariff, as they are today.

ISSUE NO. 3: Objectives of Resource Adequacy

One of the issues identified through the Commission-established stakeholder process is "What are the objectives of establishing a long-term resource adequacy requirement." In its May 1 Filing, the CAISO indicated that a primary objective of ACAP was to support reliable system operation. In addition, the CAISO noted that an ancillary benefit of its ACAP proposal was that the proposal would provide a platform for future investment in California's electric infrastructure. The CAISO reasoned that such a mechanism would provide incentives for LSEs to enter into long-term contractual arrangements with suppliers to satisfy their capacity obligations. Of course, any such arrangements could be the financial basis or support for such suppliers to build new generation/demand-based capacity. The CASIO continues to believe such objectives are attainable and worthwhile.

In addition, as part of the RAWG process, the RAWG developed and agreed upon the "mission" of the working group. The RAWG resolved that the mission of the group was to

> *Develop a consensus recommendation for a mechanism to ensure an adequate quantity of electrical resources (generation, transmission and demand-side) is available to meet anticipated peak load requirements.*

In addition, the RAWG resolved that the mechanism should be designed with the following objectives in mind:

- Minimize cost to consumers and participants;

- Recognize appropriate regulatory jurisdictions and include complementary rate or market structures;
- Maintain local and system reliability;
- Allocate costs based on causation and avoid inequitable cost shifting;
- Respect property rights;
- Create a viable and stale platform that promotes incentives for future investment in infrastructure and resources in the right place;
- Provide sufficient resources to allow efficient short run operations;
- Ensure appropriate compensation for resource providers;
- Appropriately count the value of resources, including renewables, existing contracts and demand-side resources;
- Rely on competitive, market-based mechanism where practical;
- Apply appropriate mitigation;
- Clearly identify and allocate the responsibilities of market participants.

The CAISO supports the mission statement and objectives developed and identified by the RAWG. The CAISO believes that such objectives and purpose are common to both State and, if necessary, Federal efforts on this issue.

ISSUE NO. 4: Phase-in Resource Adequacy Requirements

With respect to the phase-in of a resource adequacy obligation, the CAISO has long advocated a measured approach to phasing in any resource adequacy requirement. As stated in the May 1 Filing, the CAISO proposed that its ACAP proposal not be implemented until 2004. The CAISO's primary reason for proposing a delayed implementation was to ensure that LSEs have a reasonable amount of time to procure the capacity necessary to satisfy the requirement. The CAISO was, and remains, concerned that if LSEs are not provided adequate time to procure capacity, they will be subject to the exercise of market power by suppliers. Stated differently, knowing that LSEs must procure sufficient capacity to satisfy their obligations, sellers will demand high prices for that capacity. Clearly, that would be a sub-optimal outcome.

The difficulty is determining how long implementation should be deferred. Ideally, one would want to provide enough time for LSEs to exercise the "build" option. That is, provide enough time so that, if faced with paying exorbitant prices for capacity from existing suppliers, LSEs could instead opt to build their own capacity. However, it takes a minimum of approximately three years to build new capacity in California, and that may be too long. Alternatively, a LSE could develop sufficient demand-response to comply with a resource adequacy requirement. However, because demand programs generally are undertaken by State authorities, it is unclear how long it may take to develop such programs. Thus, the matter of selecting a phase-in schedule for a resource adequacy requirement is more art than science and requires trade-offs among a number or variables. At the time of the May 1 Filing, the CAISO believed that an eighteen-month delay was sufficient. At this time however, in light of the six-month lapse since the filing, implementation of any resource adequacy requirement may have to be delayed until mid-2004 at the earliest. Notwithstanding a delay in the implementation of a formal requirement and, thus, the potential imposition of penalties for non-compliance, the CAISO supports moving ahead and establishing the information and validation framework necessary to administer a requirement. The CAISO could begin to assess, on an information basis, whether load-serving entities that use the CAISO grid are or have procured sufficient capacity to satisfy their peak load requirements.

However, the CAISO will defer establishing any formal requirement on LSEs that use the CAISO-controlled grid at this time. The CAISO supports further development of State or local regulatory authority-established resource adequacy standards.

ISSUE NO. 5: What is the Appropriate Planning Horizon?

One issue currently under consideration before the RAWG is the appropriate planning horizon as it relates to developing a resource adequacy proposal. In its May 1 Filing the CAISO did not submit a definitive proposal with respect to this issue in its May 1 Filing. As previously explained, the focus of the CAISO's ACAP proposal was supporting real-time operations and, as such, the timeframe addressed by the ACAP proposal was near to short-term. That is, the CAISO contemplated establishing a minimum reserve margin requirement that could be adjusted on a periodic basis, perhaps annually. Once the reserve level obligation was established, the CAISO proposed that the CAISO would determine and assess whether each LSE had procured sufficient resources (capacity) to satisfy its requirements (projected load plus reserves) on a monthly and daily basis. However, the CAISO recognized that a longer-term planning horizon was appropriate. The CAISO believes that determination of a longer-term planning horizon is necessarily an issue that needs to be addressed by local and regional authorities. In fact, in its May 1 Filing the CAISO took notice of the ten-year horizon that is the basis of the Western Electricity Coordinating Council's Annual Loads and Resources assessment.

The preliminary position of the RAWG subgroup is that a three-five planning horizon might be appropriate. This proposal is based on that fact that it generally takes about three years to site new generation and about five to seven years to site new transmission. The preliminary recommendation of the subgroup is that it may also be appropriate to establish both a "planning" horizon as well as a shorter-term "operating" horizon, such as one year. The concept of a three- year planning horizon also comports with that proposed as part of the SMD NOPR.

The CASO supports the establishment of, at a minimum, a three-year planning horizon. Such a product could be used by potential suppliers as a means to partially hedge risk when offering their capacity to load-serving entities on a three-year forward basis.

ISSUE NO. 6: Resource Eligibility – What Kind of Resources Should Be Able To Satisfy the Resource Adequacy Requirement?

In the May 1 Filing the CAISO proposed that all firm resources be eligible to provide ACAP. Thus, the CAISO proposed that all existing and new generation, including thermal, hydro, renewable, qualifying facility-type generation be eligible to provide capacity. In addition, the CAISO stated that demand-based products, including load under IOU interruptible programs, should be eligible to provide ACAP. Finally, the CAISO stated that existing firm energy contracts and contracts for imported form energy also should be eligible to provide ACAP.   The CAISO continues to support these positions.

The CAISO notes that the SMD NOPR states that only identifiable physical resources should be able to provide capacity to satisfy a resource adequacy requirement. The CAISO disagrees with this position, in part. While the CAISO agrees that all resource adequacy-contracted or qualified capacity within a transmission provider's control area should be tied to a physical resource, the CAISO also supports participation by out-of-control area resources – defined as "System Resources" under the CAISO Tariff – that are not necessarily identified with a specific physical resource.

The CAISO believes that the pertinent issue before the Commission is not *what* resources should be eligible to satisfy a resource adequacy requirement – all firm resources should be eligible – but *how much* of a resource's capacity should qualify or count towards satisfying a resource adequacy requirement. The CAISO does not believe that a 100 MW resource whose historical availability is only seventy percent should qualify to provide the same amount of capacity towards a resource adequacy requirement as a 100 MW resource whose historical availability is ninety percent. The CAISO hopes and believes there is consensus, in principle, within the RAWG on this issue. The difficult issue is determining historical availability. Should the amount of capacity eligible to satisfy a resource adequacy requirement be that which was available ninety-eight percent of the time last year or ninety percent of the time? Should hydroelectric facilities be evaluated based on historical energy output? Should their eligible capacity be adjusted based on expected hydrological conditions? These are difficult issues. The CAISO did not present a specific proposal in its May 1 Filing on this issue. Moreover, at present, while the RAWG has discussed and examined this issue, it too has not developed a specific proposal, although it has made progress on these issues.

The challenge is to develop a policy or accounting methodology that does not inappropriately discount available capacity and, thereby diminishing the value of the affected resource and potentially raising costs to LSEs (and consumers) that are required to purchase additional capacity. Moreover, policies designed to encourage the development and use of renewable resource can be undermined by accounting methodologies that fail to account the full "value" of such a resource. While such matters are typically addressed in state forums, the California state agencies have not yet developed standard policy on the issue of how to rate resources. As further detailed in Appendix A, while this issue may eventually be addressed by the CPUC for the State's investor-owned utilities in the CPUC's procurement rulemaking, the CPUC has not yet addressed this issue. Comparable standards may need to be established for all resources and for all load-serving entities that use the CAISO Controlled Grid.

At this time, however, the CAISO believes it is premature for the Commission to make any determination on this issue, and the CAISO intends to support the resolution of this issue, in the first place, before State regulators. State regulators historically have considered not only reliability-related issues, but also other public policy issues, such as environmental impact. Thus, State regulators can address resource eligibility issues.

ISSUE NO. 7: Market Power Mitigation – What Type of Market Power Mitigation Mechanisms/Strategies Can Be Incorporated into a Long-Term Resource Adequacy Requirement or Mechanism?

As indicated in the CAISO's May 1 Filing, the CAISO believes that the principal strategy to mitigate the exercise of market power in the capacity (resource adequacy) market is to ensure and facilitate entry into the market. In order to facilitate entry to the market, the timeframe to fulfill the obligation to procure capacity has to be long enough to ensure that new capacity or demand-based resources can enter the market. Consistent with the CAISO's position on the planning horizon outlined above, the CAISO generally believes that a multi-year horizon is appropriate. Thus, the CAISO supports a resource adequacy requirement that is forward-looking – similar to that proposed in the SMD NOPR – and provides sufficient time for LSEs to procure or build new capacity if existing capacity resources continue to demand exorbitant prices for their capacity.

Alternatively, the Commission may be required to impose some form of price mitigation on the forward capacity market. That would be sub-optimal and could distort forward-market prices. Moreover, such mitigation surely would discourage new investment. However, the CAISO recognizes that certain locally-constrained capacity may be able to exercise market power, and such resources with local market power should be subject to some form of cost-based mitigation, similar to that in place for Reliability Must-Run Generation in California). In any event, the Commission should be vigilant in monitoring prices in the bilateral forward capacity market.

In conclusion, the CAISO believes that adequate and prudent long-term forward-contracting is the best means to mitigate market power. Therefore, the State's efforts toward establishing a policy and regulatory/institutional framework that supports forward contracting (at least for the State's IOUs) are of paramount importance. Absent that framework, California may once again find itself in a crisis situation.

<u>ISSUE NO. 8: Penalties/Incentives – What Type of Incentive/Penalty Mechanism Should Be Incorporated into a Long-Term Resource adequacy Requirement or Mechanism?</u>

The CAISO supports the inclusion of incentive mechanisms in any established resource adequacy proposal or mechanism. In particular, it is ofutmost importance that the State (specifically the CPUC) should establish clear rules and consequences for the IOUs with regard to forward-market procurement activities. Specifically, the CAISO supports the adoption by the CPUC of explicit penalties/sanctions for IOUs that fail to follow CPUC-established procurement guidelines. Such penalties should be established at a level necessary to provide sufficient incentives for the IOUs to comply with the set rules and should be tied to the cost building new resources.

With respect to any CAISO-oriented resource adequacy requirement ultimately deemed to be necessary, the CAISO also believes that it is imperative that the Commission establish clear rules and consequences for non-compliance. Absent the creation of an incentive-compatible resource adequacy mechanism, load-serving entities will fail to comply and the CAISO may be once again be forced to satisfy large amounts of load through the spot market – an outcome that will inevitably lead to higher prices.

The CAISO's May 1 Filing provided that LSEs that failed to procure sufficient capacity on a month-ahead and day-ahead basis would be subject to either financial penalties or priority curtailment before the CAISO entered into a reserve deficiency period. The CAISO reasoned that such penalties/curtailments were necessary to ensure that load-serving entities had proper incentive to procure capacity in the forward market. The CAISO continues to believe that proper incentives are necessary to motivate compliance with a resource adequacy requirement and notes that the eastern ISOs/Power Pools all assess comparable penalties for non-compliance with their established capacity requirements. Absent such penalties, the CAISO is convinced, based on past experience, that LSEs will take the risk that necessary power will be available in the spot market – especially if such spot markets are subject to price mitigation measures.

The RAWG has also discussed this issue. At this juncture, the CAISO believes there is uniform agreement that, at a minimum, it is appropriate for the CAISO to assess a surcharge for real-time energy purchased during a Stage 1, 2 or 3 Emergency. That is, most participants appear to agree that the CAISO should impose graduated penalties on LSEs that are determined to be capacity short in the Day-Ahead, for imbalance energy based on system conditions. For example, if the CAISO were to go into a Stage 1 Emergency (operating reserves fall below seven percent), the CAISO should charge a $100/MWh surcharge on energy purchased by capacity-short load-serving entities from the CAISO's real-time market. In a Stage 2 Emergency, a $250/MWh surcharge would be assessed and in a Stage 3, a $1000/MWh surcharge. The CAISO believes that such an approach is similar to that proposed in the SMD NOPR.

To date, the CAISO is not aware of anyone that supports penalties applied on a month-ahead or longer basis. As articulated by certain participants in the RAWG process, such penalties necessarily and inappropriately impact LSE procurement practices and discretion – matters these entities believe are best addressed or overseen by local regulatory authorities. The CAISO acknowledges these concerns and, as stated above, supports development of such penalties coincident with the development of procurement rules by local regulatory authorities.

Therefore, should a CAISO-established resource adequacy mechanism be deemed necessary by the Board after their November '03 meeting, and in order to move resolution of this issue forward, the CAISO is prepared to support an alternative approach to that it proposed in the May 1 Filing. The CAISO proposes that, instead of assessing penalties based on a forward-market assessment of resource adequacy, the CAISO instead establish a forward-market priority curtailment list, to be utilized in real-time if necessary. The priority curtailment list would be based on information required to be submitted by LSEs on a periodic basis – perhaps monthly. Such priority curtailment list would be made public and published on the CAISO website. Thus, LSEs could effectively “buy down” their curtailment priority by procuring more capacity. On a real-time basis, prior to the CAISO going into a Stage 3 Emergency, the CAISO would curtail the firm load of load-serving entities based on the priority curtailment list. In addition, similar to the proposal outlined above, all LSEs that were capacity short in the Day-Ahead market that choose to rely on the CAISO’s real-time energy market during a Stage 1, 2 or 3 Emergency would be assessed a surcharge on such energy. The CAISO believes that such an approach should establish the appropriate incentive for load-serving entities to procure sufficient capacity in the forward market.

ISSUE NO. 9: Pooling of Resources – Can the CAISO Dispatch One Load-Serving Entity’s Capacity To Meet Capacity Deficiency by a Different Load-Serving Entity?

There are two fundamental objectives with respect to resource adequacy: (1) ensuring that each LSE fulfills its obligation to procure, in the forward market, sufficient resources to satisfy its load, including a planning reserve margin; (2) ensuring that resources are made available to the market in manner that support reliable system operation and achieve the benefit of coordinated operations and reserve sharing. In the context of the RAWG discussion, a number of parties have raised concerns about the use of “their” resources by the CAISO in the context of the forward-market commitment and real-time dispatch rules of the CAISO.

As recognized in the CAISO’s May 1 Filing and in the State’s resource-adequacy-related proceedings, the capacity obligation of a LSE can be satisfied by a combination of resources, including those that are energy-limited (number of MWhs) or time limited (number of hours) during the reference capability period (annual, monthly, weekly, or daily). These are generally referred to as “use-limited” resources. Concerns about pooling of capacity resources apply primarily to such use-limited resources. The Scheduling Coordinator responsible for scheduling and/or bidding such resources in the CAISO’s day-ahead, hour-ahead and/or real-time spot markets, would do so with a view to the opportunity cost of such resources over the entire capability period. The CAISO affirmatively believes that it is the right and obligation of the Scheduling Coordinator responsible for managing a resource in the context of the CAISO’s markets to schedule that resource, in the first instance, as that Scheduling Coordinator sees fit. Thus, the CAISO supports maximum Scheduling Coordinator self-discretion when it comes to scheduling a resource to satisfy a Scheduling Coordinator’s own load.

However, under certain limited conditions, the CAISO does support use, by the CAISO, of such resources to obtain the benefits of coordinated reserve sharing - most notably, reliable system operation. The CAISO would not use the unscheduled energy or the protected energy bids of the use-limited resources of one Scheduling Coordinator to make up for another's lack of resources based on economic considerations. However, under pre-specified system conditions (*e.g.*, declaration of monthly peak hours in the forthcoming Operating Day) or contingency conditions (e.g., occurrence of a contingency in a pre-specified contingency list) the CAISO does support the "pooling" of the use-limited resources of all Scheduling Coordinator's to maintain reliable system operation[34].

The market participant whose use-limited resource is utilized by the CAISO beyond the level envisaged in the daily resource plan (compatible with the LSE's capacity obligation) and, as a consequence, the resource is exhausted before the end of the capability period, should not be subject to any defined penalties (capacity deficiency charge or load curtailment) in the remaining part of the capability period[35].

It is the CAISO's understanding that most of the RAWG options/proposals under discussion require that LSEs identify resource capacity, prior to a month ahead, that they plan to use to satisfy their resource needs with a necessary amount of margin (115%-122% of peak load). However, it has not been decided what obligation should be placed on the identified capacity. Certain proposals include an obligation to pool the capacity together to meet control area resource

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[34] One issue that remains is how to implement with load curtailment of the load-serving entities that are deficient in meeting their capacity obligations. One proposal is to curtail such load-serving entities' loads if they are deficient in meeting their month-ahead obligation, and remain deficient in the day-ahead, before calling upon other Scheduling Coordinator's use-limited resources (pooling). Another proposal is to curtail such load-serving entities' loads only when the CAISO gets to Stage 3 emergency, but do so before curtailing loads of other load-serving entities.

[35] It would of course have to pay for real-time purchase of energy (the exemption would apply to the penalties); it could, however, internalize the lost opportunity cost of using its energy during such periods in its use-limited resource energy bids.

needs during capacity shortages, while other proposals have minimal obligations tied to the capacity and propose to rely on the existing must-offer mechanism to address emergency conditions.

The CAISO believes that most of the RAWG participants seem to agree that pooling of the excess resources for use by the CAISO during emergency conditions is necessary. For example, "LSE" 1 loses some of its resources due to a forced outage and the CAISO is now in a Stage 2; so, the CAISO needs to "pool capacity" and use some energy limited resources acquired by "LSE 2" and "LSE 3" in order to restore the necessary reserve margin to meet the WECC Minimum Operating Reliability Criteria ("MORC").

However, a number of issues remain, including:

1. How to manage energy limited resources? In the above example, "LSE 2" and "LSE 3" would be concerned that their energy limited resources won't be available when they need them at some later date.

2. How are "LSE 2" and "LSE 3" in the example above compensated for the use of their energy limited resources? "LSE 2" and "LSE 3" may have to buy energy at a higher cost later.

3. Under what conditions is the CAISO allowed to pool (e.g. prior to or during Stage 1, 2, or 3).

4. When can the CAISO pool resources? Prior to or during day-ahead, hour-ahead, or real-time?

5. How long after the initial incident causing the emergency conditions can the CAISO pool resources?

6. Can the CAISO pool resources in lieu of shedding firm or non-firm load?

First and foremost, the basis question – whether the CAISO use one LSEs resources to serve another's load – must be answered before these other issues can be addressed.

ISSUE NO. 10. Level of Obligation – What Should Be the Level of the Resource Adequacy Requirement?

The general guideline historically followed in the industry is that an adequate planning reserve is one that would limit reliability risk to one-day-in-ten-years loss of load probability. In the May 1 Filing, the CAISO proposed that LSEs maintain a capacity reserve level of 10% to 12% based on "unforced capacity" in the forward (month-ahead) time frame and about 10% based on "available capacity" in the day-ahead time frame. According to the SMD NOPR, a 12% minimum margin is necessary. At the state level, both the CPUC and the CPA appear to support, at this time, a reserve level between 15% to 22% of installed capacity. However, the RAWG group has not yet come to an agreement regarding the level of obligation.

The CAISO believes that planning reserve levels should be established by State, local or regional authorities. Only after such reserve levels are clearly defined, should the CAISO consider whether other *minimum* standards for users of the CAISO system are necessary and what that minimum reserve level should be.

ISSUE NO. 11: Who Should Forecast the Load?

In its May 1 Filing, the CAISO proposed that the CAISO establish and determine a system-wide reserve requirement or obligation and then determine each LSEs share of that obligation by examining and allocating based on a load-serving entity's historical contribution to the peak load of the system. The CAISO reasoned that, while not precise, such an approach was fair and would reduce or eliminate incentives for LSEs to manipulate their load forecasts to reduce their reserve obligation.

A number of parties, including LSEs and State agencies objected to that approach, stating that it gave the CAISO too much discretion and could result in the CAISO imposing unreasonable costs on LSEs by imposing a reserve requirement based on an inaccurate historical load profile.

The RAWG acknowledged that if capacity obligations are not to be imposed three years out, load forecasts can be done by the LSEs, with the CAISO "using" them as it sees fit. If obligations are imposed, most parties feel that non-coincident peak forecasts by the LSEs should be used in setting obligations; although, it was acknowledged that the CAISO is best positioned to do a system-wide forecast, which should be used to assess system-wide capacity needs. However, forecasting-related issues were not considered to be a primary issue.

ISSUE NO. 12: Should There Be a Deliverability Requirement for Capacity?

The latest RAWG working document states that the CAISO should identify local generation requirements for reliability. CAISO analysis would include benefits of firm transmission projects. LSEs with load located in a transmission-constrained area would need to acquire the identified amount of their capacity requirement within the same transmission constrained area. This approach is similar to that proposed by the CAISO in its May 1 Filing. Thus, under such a proposal, by defining “locational” resource adequacy requirements, the CAISO would remove the need to determine whether resource adequacy resources were “deliverable.”

The CAISO continues to believe such an approach is viable. However, as noted above, before making any determination regarding the need for and details of a CAISO-established resource-adequacy requirement, the CAISO recommends that the Commission defer any action until State efforts on resource adequacy are finalized.

D. Summary for Resource Adequacy Requirements

The CAISO believes that by proffering these specific comments on the form and function of a workable resource adequacy requirement, the CAISO will assist both State and Federal policymakers in establishing a resource-adequacy framework that works for all parties and supports reliable and reasonably priced electricity. In support of those efforts, the CAISO intends to submit these comments to both the Commission and affected California State agencies.

VII. CONCLUSION

Wherefore, for the foregoing reasons, the CAISO requests that the Commission act on the CAISO's MD02 Filing in a manner consistent with the discussion herein and the CAISO's presentation at the December 9, 2002 MD02 technical conference. In particular, the Commission should allow the CAISO to integrate the various Working Group recommendations and present a comprehensive proposal to stakeholders.

Respectfully submitted,

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Filed: December 2, 2002

ATTACHMENT A

Memorandum

To: ISO Board of Governors **{** FORMTEXT **}**

From: Elena Schmid, Vice President, Corporate & Strategic Development
Steve Greenleaf, Director of Regulatory Policy

cc: ISO Officers, ISO Board Assistants

Date: November 15, 2002

Re: ***Market Design 2002: Status of MD02 Working Group Activities and Update on State Initiatives.***

This memorandum does not require Board action.

EXECUTIVE SUMMARY

At the October 24, 2002 ISO Governing Board meeting, the Board directed management to update the Board at the November Board meeting regarding the status of the ISO's Market Design 2002 (MD02) initiative and the impact of various state initiatives on that effort. Specifically, the Board directed management to report on the status of certain state initiatives and whether, based on the progress of those efforts, the ISO had a clear vision of the future market structure. If so, the Board directed management to reconcile the MD02 proposal with that end-state vision of the market.

The following memorandum 1) updates the Board on the progress of the ongoing MD02 stakeholder process and 2) briefly summarizes various state initiatives and how those initiatives relate to the ISO's MD02 proposal. In conclusion, while recognizing the significance and progress of the various state initiatives, management states that because these efforts are not final, and that many details remain to be clarified, the MD02 proposal should not be modified at this time.

BACKGROUND

On May 1 and June 17, 2002, the ISO filed at FERC its MD02 proposal. The MD02 filing proposed a comprehensive redesign of the ISO's markets. Phase I of the MD02 proposal, proposed to be effective October 31, 2002, included various price mitigation measures that were intended to replace expiring FERC price mitigation measures, as well as certain enhancements to the ISO's real-time market. Phase II, proposed to be effective in the Spring of 2003, provided for the establishment of, among other things, an integrated forward energy market that would simultaneously perform energy trades, manage transmission congestion and procure ancillary services. Phase III, proposed to be effective in the Fall of 2003, would build upon the previously established integrated forward market and implement Locational Marginal Pricing ("LMP" or "nodal pricing"), including a means to hedge price volatility through instruments called "Congestion Revenue Rights" (similar to the existing Firm Transmission Rights).

On July 17, 2002, FERC issued an order (July 17th Order) that accepted, subject to certain modifications, the critical elements of the ISO's Phase I price mitigation proposal. The July 17th Order also accepted other limited aspects of the ISO's MD02 proposal. Finally, the July 17th Order directed the ISO, along with its stakeholders, to pursue through a "Technical Conference" process, resolution and refinement of the MD02 proposal. FERC convened the first such technical conference on August 13-15, 2002. Subsequent to that technical conference the ISO, with the support of stakeholders, created four "Working Groups" to address, and hopefully resolve through a consensus-building process, many of the policy and design issues left un-addressed by FERC in the July 17th Order. It is important to note that, in order to increase stakeholder commitment and dedication to the process, each of the four working groups is "sponsored" by one segment of the stakeholder community. The four Working Groups, and their sponsors, are:

1) **Resource Adequacy** – State Inter-agency Working Group;
2) **Integrated Forward Markets** – the investor-owned utilities (Southern California Edison Company, Pacific Gas & Electric Company, and San Diego Gas & Electric Company);
3) **Interim Market or Transitional Issues** - Suppliers; and
4) **LMP/CRR** – the municipal utility community.

FERC has now convened, in response to an ISO request, a technical conference on MD02 for December 9, 2002. The purpose of that conference will be to discuss and obtain clarity on the MD02 implementation process and timeline, to provide FERC an update from the above-identified Working Groups on the progress of the MD02 Working Groups in resolving all open design issues, and to request guidance on the procedural steps for finalizing and obtaining FERC approval for the MD02 Tariff changes and on the continuing role of the working groups.

DISCUSSION

Update on Working Group Activities

As noted above, the ISO, in cooperation with its stakeholders and effected state agencies, created four working groups to address unresolved MD02 policy and design issues. The purpose and activities of each of those working groups is summarized below. Specifically, the summaries identify the adopted "mission" of each of the working groups and the "priority issues" each group is addressing. To date, most if not all of the issues identified by the Working Groups have not yet been resolved.

Resource Adequacy Working Group

The Resource Adequacy Working Group (RAWG), sponsored by the State's Inter-Agency Working Group (IAWG), met for the sixth time November 6, 2002. The group's mission statement is to develop, by the end of December, a consensus recommendation for a mechanism to ensure an adequate quantity of electrical resources (generation, transmission and demand-side) is available to meet anticipated peak load requirements. The highest priority issues revolve around the question of which regulatory body has jurisdiction over resource adequacy, and what the role of the ISO will be. Another major issue is the question of how far in advance load serving entities should be required to demonstrate resource adequacy, and whether there is a physical penalty (load shedding priority) as well as a financial penalty for not meeting the requirement.

Mission

Develop a consensus recommendation for a mechanism to ensure an adequate quantity of electrical resources (generation, transmission and demand-side) is available to meet anticipated peak load requirements.

The mechanism should be designed with the following objectives in mind:

- Minimize cost to consumers and participants
- Recognize appropriate regulatory jurisdictions and include complementary rate or market structures
- Maintain local and system reliability
- Allocate costs based on causation and avoid inequitable cost shifting
- Respect property rights
- Create a viable and stable platform that promotes incentives for future investment in infrastructure and resources in right places
- Provide sufficient resources to allow efficient short run operations
- Ensure appropriate compensation for resource providers
- Appropriately count the value of resources, including renewables, existing contracts and demand side resources
- Rely on competitive, market-based mechanisms where practical
- Apply appropriate mitigation
- Clearly identify and allocate the responsibilities of market participants.

Meetings to Date

The Resource Adequacy Working Group has met on six occasions. The sub-groups have also met on a number of occasions.

Priority Issues

1) Which regulatory body has jurisdiction over resource adequacy, and what will the role of the ISO be?

Other major issues:

2) Obligation to demonstrate 100% sufficient capacity in advance vs. reporting only obligation of capacity procurement information.

3) "Pooling" of resources issue – how/under what criteria will resources be used/called upon by the ISO in the forward markets and how will they be compensated?

4) ISO procurement role, (i.e. no procurement role or centralized/backstop procurement role – perhaps through capacity auctions?)

5) Amount of capacity allowed to be procured from imports

6) Rating of allowable resources: thermal, hydro, wind, contracts etc.

Integrated Forward Markets Working Group

Mission

To deliver by Thanksgiving ’02, consensus recommendations on the open issues related to the form and function of the Integrated Forward Market (IFM) in a manner consistent with a best practices approach to FERC’s Standard Market Design.

Principles

Recommendations will:

- *Support the ISO’s core functions, i.e. the reliable, safe and predictable operation of the grid and providing non-discriminatory access;*
- *Rely on competitive market-based mechanisms and lessons learned wherever possible;*
- *Be approved at the working group level with consensus. Where this is not possible, the working group will identify the majority opinion and will capture concerns and objections to the majority opinion.*

Evaluation Criteria

The Integrated Forward Markets Working Group agreed on the following criteria to be used in evaluating solutions.

- Implementation feasibility
- Supports ISO core functions
- Relies on competitive market mechanisms
- Incorporates lessons learned
- Broad market participant support
- Upfront disclosure on openness to change

Integrated Forward Markets Working Group Open Issues

This Working Group ranked the high priority open issues described in the Statement of Issues document as follows:

1) Treatment of bilateral schedules.
2) Virtual bidding; if/when; form and function.
3) Residual Unit Commitment – form and function, including:
    - Treatment of Transmission
    - Must-offer considerations
    - Objective function
    - Residual Unit Commitment Capacity Payment?

4) Need for, and timing of, an Hour Ahead market

5) Market Mitigation in the Forward Markets

6) Payment for A/S Capacity

7) What actions does ISO take in the event of a supply shortage?

Meetings to-date

The IFM-WG has met six times, for the final time on Wednesday, November 13, 2002.

Locational Marginal Price/Congestion Revenue Rights Working Group

Mission Statement

The Mission of the Working Group is to identify and understand issues associated with application of LMP in California as proposed in MD02 (including congestion hedging instruments such as Firm Transmission Rights, Congestion Revenue Rights, etc.), enumerate options for solving potential problems, and recommend consensus solutions if possible.

Meetings Held

There have been four meetings and one conference call. At the October 24th meeting, the working group established two sub-groups. There were various conference calls for each of the sub-groups that were not tracked, as well as a couple of independent meetings for these subgroups.

Priority Issues

1) Release of LMP base case assumptions.

2) Equity concerns, i.e. phase in or full LMP pricing (load aggregation)

3) Conversion of Existing Transmission Contracts (ETCs) to CRRs

4) Allocation of CRRs to Load Serving Entities and definition of an LSE.

5) Use of an AC or DC OPF model (real-time versus forward markets)

6) How the Full Network Model will account for external schedules/sources and what type of equivalency will be performed.

7) Criteria and/or standards used for judging outcomes of the state estimator

8) Objective function of the LMP

Following are the priority issues that the working group has identified and discussed to date.

Transitional Issues Working Group

The original charter of this working group was to identify and focus on the development of market features that are needed to be in place between now and the implementation of the long-term market design. Consistent with that charge, the working group originally focused on the design of an interim residual unit commitment (RUC) mechanism, presuming that it was a necessary and appropriate to transition from the existing must-offer waiver process, or, in the alternative, to identify changes to improve the existing waiver process. In addition, the working group was to focus on the need for and details of an interim forward energy market. Subsequent FERC orders have substantially reduced the urgent need to focus on those matters by rejecting the notion of establishing any kind of interim RUC proposal and by, despite the ISO's objections, directing the ISO to establish an interim forward energy market. Thus, as it currently stands, this working group is on hold subject to further refining the MD02 project schedule and assessing the need for any interim market features.

As noted above, FERC has scheduled a technical conference to, among other things, get an update on the progress of the Working Groups in resolving open MD02 design issues. One hoped-for result of the technical conference will be further direction from FERC regarding the timing and process for resolving MD02-related issues.

Update on State Initiatives

As a result of the 2000-2001 California electricity crisis and the need to implement necessary reforms in the electric market, California state energy agencies have embarked on a number of ambitious reforms. The summaries provided below focus on certain ongoing initiatives at the California Public Utilities Commission (CPUC), the California Energy Commission (CEC) and the California Consumer Power and Conservation Financing Authority (CPA). As management has emphasized since it began the MD02 effort, redesign of the ISO's markets is only one element of the solution of California's electricity problems. Each of the programs identified below is an essential part of that solution, and as such shares common policy objectives and has critical linkages to the ISO's MD02 proposal.
The state agencies' efforts fall into three general areas, each of which has traditionally been a state-focused activity:

1) Integrated resource planning/ procurement activities for the state's IOUs;
2) Demand-side programs; and
3) Distribution system issues.

The primary focus of this discussion will be on the first two areas, as these are the areas that bear the most significant relationship to the MD02 proposal.

In summary, management does not believe that any of the ongoing state initiatives requires the ISO to revisit or substantially modify the MD02 proposal at this time. This is not to diminish in any way the importance of those state initiatives or the progress they have made to date. The state programs, in combination with the ISO's MD02 proposal, will form the foundation of the market and institutional framework for stimulating investment in the California energy infrastructure and providing sufficient, reliable electricity supply for consumers. The programs initiated by the California state agencies this past year are critical to the success of that endeavor. At this juncture, management believes that these efforts are necessary complements to the MD02 proposal, rather than duplicative of or in conflict with it.

California Public Utilities Commission (CPUC)

1. Procurement Rulemaking

The CPUC's procurement rulemaking has both a short-term and a long-term focus. The short-term focus (for 2003) is to establish policies and rules that enable the IOUs to return to creditworthy status and to resume procurement of power on behalf of their customers.

On a longer-term basis, the rulemaking appears focused on the creation of a policy framework that reestablishes the IOUs' traditional obligation to serve, requires the IOUs to procure power to a level that supports reliability and minimizes their exposure to volatile spot markets while providing for the timely recovery of prudently incurred costs. Both short-term and long-term procurement plans are to include similar elements. The salient draft determinations of the CPUC include:

- **Allocation of CDWR Contracts** - The CPUC allocated DWR contracts among the state's three largest utilities and ordered an on-going procurement planning process to cover the short-term (through 2003) and long-term (for 2004 through 2023.) The CPUC's order on September 19, 2002, allocated 35 DWR contracts representing annual capacity of 10,780 MWs over the next seven years. This allocation among PG&E, Edison, and SDG&E is one of the key factors underlying the derivation of each utility's residual net short position. ("Net short" is the difference between customer loads and the power already under contract to the utility.).
- **Short-term procurement (2003) Plans** - The three utilities must update their short-term (2003) procurement plan by November 12th, including estimates on the collateral needed for participation in ISO. In addition, the CPUC directed Edison and PG&E to post the required ISO collateral in order to resume Scheduling Coordination and purchase of the net-short. The CPUC anticipates final approval of these plans at the Commission's December meeting.
- **Renewable Generation** - The CPUC directs the utilities to submit, with their short-term procurement plan on November 12, 2002, a report on the status of their procurement under the renewable generation mandate of its previous order. Utilities should document their plan for meeting the 1% procurement, including what has been accomplished and what remains to be done. The CPUC defined "Renewable generation" as electricity produced by the following technologies: biomass, solar thermal, photovoltaic, wind, geothermal, fuel cells using renewable fuels, small hydroelectric generation of 30 megawatts (MW) or less, digester gas, municipal solid waste conversion, landfill gas, ocean wave, ocean thermal, or tidal current. In its definition of renewable generation, the CPUC also includes distributed generation (DG) on the customer side of the meter.

  The 1% purchase requirement is to be calculated based on 2001 sales figures. Utilities are required to contract for this amount of electricity from renewable sources by the end of 2002. Utilities are not required to procure all resources that offer prices of less than 5.37 cents per kWh (the interim benchmark price). That benchmark was set for purposes of determining *per se* reasonableness for cost recovery purposes, but does not require that utilities acquire all resources at that price.

- **Reserve Guideline** - The CPUC will require the utilities to procure reserves at the 15% level (general guideline)
- **Economic Dispatch** - The CPUC proposes that the IOUs follow economic dispatch for their resource portfolio – not the previous practice where utilities scheduled resources based on allocated costs and gave priority for dispatch to their own generation. Thus, for example, the IOUs will have to directly factor in the costs of dispatching power under their allocated CDWR contracts.
- **Ban on Affiliate Transactions** - The CPUC proposes to ban utility transactions with affiliates except through ISO markets. The moratorium on utility transactions with affiliates will thus not include transactions through the ISO that "can be demonstrated to include multiple and anonymous bidders."
- **Participation in ISO Markets** - The utilities "should try to minimize" their exposure to the ISO spot market and must justify planned spot market purchases if they exceed 5% of monthly needs. In addition, the interim ruling authorizes the utilities to use ISO spot market transactions to balance system and meet short-term needs. The CPUC order requires procurement plans to describe procurement strategies for hedging the utility's overall portfolio risk with ISO spot purchases and authorizes use of a day-ahead market "should it become operational."
- **Long-term Procurement Plans** - Requires the IOUs to file by April 1, 2003, long-term procurement plans (for 2004 through 2023) that include conventional generation sources – both utility-owned and merchant and with a variety of types of ownership structures, renewable generation (including renewable self-generation), distributed and self-generation, demand-side resources, and transmission. In addition, as noted above, utilities should plan to meet a reserve requirement.

  In making plans to procure a mixture of resources, the utilities should take into account the Commission's longstanding procurement policy priorities – reliability, least cost, and environmental sensitivity. While each of these priorities is important individually, the CPUC noted that they are also strongly interrelated. Increased reliability may increase procurement costs. Diversifying the resource mix may meet environmental priorities, but may also increase costs. Thus, the CPUC directed the utilities to explicitly address these tradeoffs in their long-term procurement plans.
- **Contract Review and Cost Recovery** - The CPUC seeks to provide quicker review of power contracts and more timely cost recovery for utilities. Semiannual rate adjustments will occur whenever a utility's costs exceed revenues by more than 4%. This is intended to assure ratings agencies that the utilities will be able to recover their costs.
- **Balancing Account** – The CPUC will require the three utilities to refer to their new balancing accounts as the Energy Resource Recovery Account (ERRA) instead of the names they have proposed. This common account name for

tracking energy costs among different types of energy resources would allow for comparisons among utilities.

Analysis

The short-term (2003) procurement strategies of the IOUs, as guided and administered by the CPUC's proposed rules, are not likely to effect or be effected by the ISO's MD02 proposal. While certain features of the ISO's MD02 proposal, principally real-time economic dispatch, are likely to be in place in 2003, the most significant features of the long-term market design will not be in place until the end of 2003 and early in 2004. For 2003, the CPUC suggests that the IOUs participate by no more than 5% in the ISO's spot markets; that level of participation in the market is consistent with CERS's practice over the past year. However, we note that the CPUC's proposed rule is based upon 5% of monthly needs, thus it appears that day-to-day, hour-to-hour participation in spot markets could be much higher, particularly in peak hours. Thus, the ISO is concerned that the IOUs could, as they have in the past, rely heavily on the ISO's real-time market to satisfy their demand.

The most significant short-term issue will be the transition from CERS procurement to satisfy the IOU's net short position back to IOU procurement to satisfy their full load. Debi Le Vine has been updating the Board monthly on the transition Status. In addition, as noted by the CPUC, a significant short-term issue will be the resolution of the IOUs' credit requirements for participating in the ISO's markets. PG&E and SCE had hoped to delay procurement responsibilities until return to investment grade credit ratings to avoid the posting of a financial security. The ISO is working in close cooperation with the CPUC to create satisfactory collateral arrangements with these two utilities to allow their continued participation in the ISO's markets to a level necessary to satisfy their net-short purchases. Regaining investment grade ratings for the utilities will be an important and necessary milestone before the IOUs and the CPUC can implement a long-term procurement strategy.

On a long-term basis, the CPUC's procurement rulings are likely to have a greater effect on the MD02 proposal. However, the effect is likely to be complementary in nature. The MD02 proposal and the CPUC's proposed procurement strategies share common goals: 1) supporting reliable system operation; 2) establishing a framework for forward contracting and investment; and thus 3) reducing reliance on the ISO's spot markets (and hence reestablishing the IOUs' obligation to serve their own load). Some parties view the CPUC's procurement rulings as obviating the need for certain features of the ISO's MD02 proposal, specifically the ACAP (Available Capacity) proposal.

Management does not agree the CPUC's procurement rulings obviate the need for the ISO's ACAP proposal for the following reasons:

1) **Draft Decisions** - The CPUC's determinations are draft in nature and are not likely to be finalized prior to December (short-term) and April 2003 (long-term). Thus, it would be premature to conclude that the determinations are final and binding and that these rulings solidify the vision of the "real" market going forward;

   Moreover,

2) **Applicability** - While the IOUs account for about eighty percent of the load that is served off of the ISO Controlled Grid – a significant share – the CPUC's rules would not apply to the other load-serving entities that use the ISO Controlled Grid (Direct Access suppliers, municipal systems and others). In particular, while the CPUC's 15% reserves guideline supports the ISO's requirement for the IOUs to procure sufficient supplies to satisfy their load plus reserves, the requirement will not apply to all load served off of the ISO grid. Thus, it is important to establish rules that apply to all users of the ISO's grid.

3) **Reserve "Guideline"** - As to the specifics of the 15% reserve number, the CPUC proposes that this be a general guideline for the IOUs. Thus, the actual level of reserves may vary from utility to utility based on the structure and nature of their resource portfolio. Moreover, it is unclear at this point how the resources in the utilities' filed plans will be "counted" towards satisfying the target reserve level. The IOUs long-term procurement plans will not be filed at the CPUC until Spring 2003, until these details are known, or explicit rules are established in advance by the CPUC, the ISO is unable to ascertain whether the ISO's MD02/ACAP proposal adversely impacts the CPUC's procurement rulings.

4) **Lack of Incentives** - Finally, the CPUC's draft procurement rules do not – and are not designed to – fully address the ISO's principal concern with the day-to-day, hour-to-hour reliability issues associated with supply adequacy. For example, the CPUC's rules do not provide or identify explicit enforcement mechanisms (e.g., penalties) for IOU non-compliance with proposed policies and rules. Historically, the CPUC has relied on after-the-fact prudence reviews to provide incentives for IOU compliance. At this juncture, the ISO is concerned that the lack of explicit ex ante penalties (i.e., clear consequences) for IOU non-compliance will fail to establish proper incentives for up-front compliance with the established CPUC procurement rules by the IOUs, and hence will not adequately address the ISO's need for advance assurance of adequate supply resources for reliable real-time operation, which is the goal of the ACAP proposal. While the ISO believes that the IOUs will certainly endeavor to comply with the rules ultimately adopted, past experience dictates a prudent and cautious approach. Thus the ISO is reluctant to move away from its original proposal that *some form* of penalty apply to load-serving entities that fail to procure sufficient reserves in the forward market, based on an ex ante assessment. As the CPUC finalizes its procurement rulemaking and as other broader resource adequacy-related discussions take place, the ISO may want to revisit the explicit nature and timing of its proposed penalties. However, at this point in time, and based on the fluid and uncertain state of affairs in the California market, management sees no reason to scale back or substantially modify any feature of its MD02 proposal in light of the CPUC's rulemaking initiative.

2. California Electricity Generation Facilities Standards Committee

As directed under SB 39xx, the ISO and CPUC are establishing a three-person committee to establish and review generator maintenance standards to ensure that generator repairs are justified and overall capacity availability does not unnecessarily decline.

Analysis

The maintenance standards established by this committee and the CPUC's enforcement of these standards should help prevent withholding from the market. To that end, this effort will be an effective complement to the market power mitigation features of the MD02 proposal. While primarily a CPUC initiative, close coordination between the CPUC and ISO will be imperative if this effort is to be successful.

3. Distribution-level interconnection -- Rule 21

The CPUC and CPA, in close coordination with the IOUs and other stakeholders, recently developed a detailed process for interconnecting generating facilities to distribution-level transmission lines. "Rule 21" is especially aimed at facilitating distributed generation in California.

Analysis

First, the ISO notes that this process has served as an excellent model for FERC's national rulemakings on generator interconnection policies.

Further development of Rule 21 will complement two efforts under way at the ISO: 1) implementation of the ISO's New Facility Interconnection Policy (as outlined in Amendment No. 39) and 2) the establishment of ISO policies that support the development of distributed generation in California. Both of these ISO efforts will further development of new generation in California. While neither Rule 21 (and distributed generation activities) nor Amendment 39 are directly related to the ISO's MD02 proposal, both initiatives support a primary goal of MD02 – investment in California's energy infrastructure.

4. Demand Response Initiative

The ISO recently started working with the CPUC on their Demand Response Initiative, aimed at developing Real Time Pricing (RTP) for end-use loads. All parties to this effort agree that a well-developed and functioning day-ahead energy market is key to the development of RTP – a day-ahead market price signal is necessary to elicit a Real-Time Price-driven response. Thus, the ISO's MD02 initiative, which provides for the development of a forward energy market, is a necessary and key complement to the CPUC's RTP initiative.

Consumer Power and Conservation Financing Authority (CPA)

1. Target Reserve Level

In July 2002, the CPA Board began a process to establish a statewide energy reserve level. The stated purpose of this rulemaking is to establish a target reserve level to guide the CPA's own investment strategy and, as such, will not be binding on utilities or other state agencies. However, the CPA recognizes that such a target reserve level could be used throughout the state. In an important development, the CPUC's most recent order in the procurement rulemaking outlined above directed the IOUs to procure up to a 15% reserve level (as a guideline) but explicitly took notice of the CPA's target reserve level rulemaking and stated that the reserve level ultimately adopted by the CPUC will be based on the CPA-determined target reserve level.

The CPA's draft decision proposes a target reserve level of 22%, based on installed capacity, and is purportedly set at a level to support both reliability and market stability. The CPA intends to adopt a target reserve level by the end of the year.

<u>Analysis</u>

The ISO strongly supports the basis and direction of the CPA's rulemaking and draft decision. In support of the CPA's effort, the ISO filed comments in the CPA rulemaking proceeding that provided as follows:

- **Unforced v. Installed Capacity** - The CPA's target reserve level should be based on unforced capacity or net dependable capacity – not installed capacity – as the former provides a better indicator of the supply that will be available on a daily basis;

- **Periodic Updating and Eligibility** - The CPA's target reserve level should be updated periodically, and merchant generation that is not under contract to a California Load Serving Entity should be discounted in meeting the target since its output has no commitment to sell to California;

- **Accurate Accounting of Demand-response** - The CPA's target reserve level should accurately measure demand response programs and adhere to the Western Electricity Coordinating Council's (the West's reliability council) requirements.

Management supports the CPA's initiative to establish a target reserve level and believes that such an effort can significantly reinforce and complement the goals and objectives of the ISO's ACAP proposal. As noted in the ISO's May 1 MD02 filing, while the ISO's ACAP proposal was specifically designed to support reliable real-time operations (the ISO's core function), ancillary benefits of the proposal include the creation of a platform for forward-contracting and generation/demand-side investment. The CPA's target reserve level rulemaking (as well as the CPUC's procurement rulemaking) are critical to the goal of ensuring adequate forward contracting and investment. More importantly, the CPA's rulemaking furthers the critical effort to reestablish the institutional and regulatory framework necessary to promote investment in California's energy infrastructure. As the ISO has long recognized, no one party, especially the ISO, can single-handedly fix the problems that have plagued the California electricity market.

Notwithstanding these significant developments, management continues to believe that it is appropriate for the ISO to establish grid-wide standards that support reliable system operation, including some form of capacity obligation on load-serving Scheduling Coordinators that use the ISO Controlled Grid. As recognized in the ISO's MD02 proposal, the state, through the CPA and the CPUC, may well (and probably should) establish a planning reserve level higher than that proposed by the ISO. As noted by the CPA, the benefits of reserves go beyond reliable grid operation; they also contribute to a more competitive energy market and support other public policy objectives such as the development of renewable and demand-side resources and increased fuel-source diversity. Thus, management believes that the ISO's MD02 proposal (specifically, some form of its ACAP proposal) is an appropriate complement to the broader state efforts that further attainment of goals beyond that of reliable system operation. The focus of the ISO's efforts should be on the development and implementation of the minimum requirements necessary to support reliable system operation. To that end, the ISO must establish rules that apply to all users of the grid, regardless of jurisdiction, including the IOUs, Direct Access suppliers, municipals, etc. Absent the establishment of standards or rules that apply to all users, one set of users may be disadvantaged and while others benefit from incentives and opportunities for free-riding or market manipulation.

2. Demand Reserve Partnership Program (DRPP)

The DRPP is intended to facilitate demand-side product entry into the ISO's ancillary services markets (non-spin, replacement reserve) as well as participation in the ISO's imbalance energy market. The CPA program is a cooperative program between the CPA, CDWR and the Automated Power Exchange (APX). CDWR will fund the initiative while APX will set up and provide the infrastructure necessary to support the program. The DRPP provides for contracting with third party aggregators to facilitate participation by IOU bundled load in the various ISO markets. In addition, the DRPP will facilitate IOU demand-based bidding into the ISO's ancillary services markets.

Analysis

This program is an obvious complement to the ISO's markets. Importantly, in support of this and other programs to encourage demand-based participation in the ISO's markets, the MD02 proposal included certain functionality to support demand-based bidding. Among other features, the MD02 proposal included a three-part binding structure that would enable load-based resources to bid into the forward markets in a manner sufficient to recover their sometimes significant upfront infrastructure investment. In addition, the ISO's ACAP proposal also contemplates active load-based resource participation. The ISO has also helped the CPA shape their program so that it can fit into the ISO's existing Participating Load Program. [To date, while the CPA has a signed Participating Load agreement; they have no certified resources]. The ISO also hosted a workshop on November 8, 2002, attended by the three IOUs, CEC, CPA, APX and potential aggregators, to discuss issues involving the metering process to support the scheduling, performance, and settlement of the DRPP in the ISO's ancillary services markets.

California Energy Commission (CEC)

1. Demand Response program

Currently, the CEC has number of ongoing demand programs. The CEC is actively involved in the development of real-time pricing and has sponsored the installation of interval meters (i.e., meters necessary to support real-time pricing) with $35 million of state funds.

<u>Analysis</u>

The ISO continues to work with the CEC in providing advice and comments on the design and function of their various demand response programs. As noted above, the MD02 proposal supports and facilitates active participation by demand-based resources in the ISO's markets.

2. Integrated Resource Plan

As directed under SB 1389, the CEC is developing an integrated resource plan for the state with policy recommendations and analysis of all aspects of the energy industry and markets. The plan is to be submitted to the Legislature by the end of 2003.

<u>Analysis</u>

The ISO has participated in the initial public meetings regarding development of the integrated resource plan. Specifically, the ISO has urged the CEC to emphasize:

- Coordinated transmission grid expansion;
- Facilitation of generation additions and replacements;
- Continued emphasis on demand response;
- Integrated regional planning and infrastructure operations throughout the WECC area.

The CEC's integrated plan will also require the ISO to closely coordinate with the CEC on the development and application of load and resource forecasting methodologies and instruments. The ISO expects to continue its cooperative relationship with the CEC as evidenced by our coordination on Summer and Winter Resource assessments.

The development of the integrated plan is likely to influence certain aspects of the MD02 proposal, although management does not believe that any aspect of the MD02 proposal is in conflict with the scope and charge of the CEC's integrated resource plan. The greatest likely impact of the integrated plan is on the ISO's ACAP proposal, and, more generally, the development of a California resource adequacy mechanism through the ongoing MD02 Working Groups. Both the CEC's initiative as well as the MD02 Resource Adequacy Working Group are likely to examine projected and necessary reserve levels, how resources should be counted towards satisfying any reserve requirement, and load and resource forecasting methodologies and requirements. At this juncture, management does not believe these will be duplicative efforts, as both endeavors have a unique focus and purpose. However, management proposes to remain closely engaged in the CEC effort so as to understand and potentially adjust the ISO's specific efforts to complement and potentially build off of the CEC's initiative.

3. Distribution-level interconnection -- Rule 21

The CEC continues to host a stakeholder group working on the refinement and implementation of “Rule 21.” As noted above, management believes this effort to be entirely complementary to the ISO’s own efforts to implement transmission-level interconnection requirements.

CONCLUSION

Management will continue to update the Board on the progress and developments regarding MD02 implementation. Moreover, management will continue to apprise the Board of developments at both the state and national level that may impact the timing or substance of the ISO’s MD02 proposal.

At this point in time, based upon management’s assessment of the ongoing state activities, management does not propose to modify any aspect of the MD02 proposal.

CALIFORNIA ISO

California Independent
System Operator

December 2, 2002

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

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

Investigation of Wholesale Rates of Public Utility Sellers and Ancillary Services in the Western Systems Coordinating Council
Docket No. EL01-68-017

Dear Secretary Salas:

Enclosed for electronic filing please find the Statement of Position of the California Independent System Operator Corporation in the above-referenced dockets.

Thank you for your assistance in this matter.

Respectfully submitted,

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

CERTIFICATE OF SERVICE

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

Dated at Folsom, California, on this 2nd day of December, 2002.

____

Anthony J. Ivancovich