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

REPLY COMMENTS OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION REGARDING TECHNICAL CONFERENCE

Pursuant to the instructions of the Staff of the Federal Energy Regulatory Commission ("Commission") at the technical conference held in the captioned proceeding on August 13-15, 2002 ("MD02 Technical Conference"), the California Independent System Operator Corporation ("CAISO")[1] hereby submits its Reply Comments regarding the MD02 Technical Conference.

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, with a proposed effective date of October 1, 2002, included market power mitigation measures

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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.

designed to prevent physical and economic withholding, an interim residual unit commitment ("RUC") process, and other Tariff changes.

Phase II, which had a target date of Spring 2003, included*, inter alia*, elimination of the market separation rule and balanced Schedule requirement and implementation of simultaneous 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, which had a target effective date of Fall 2003, provided for implementation of the full network model, redesigned firm transmission rights ("FTRs"), a resource adequacy obligation for LSEs, and an integrated Congestion Management, Energy, Ancillary Services and Unit Commitment Market based on LMP.

The CAISO requested that the Commission issue an order by July 1, 2002 accepting the Tariff provisions for the Phase I elements and granting preliminary conceptual approval of the Phases II and III elements. The CAISO indicated that conceptual approval of the long-term elements by July 1, 2002 was imperative because Phases II and III required extensive software and systems development and testing. The CAISO indicated in its MD02 Filing that it would need a lead-time of approximately 12-18 months to procure, install and adequately test and provide training on the new software and systems before they become fully operational.

On July 17, 2002, the Commission issued its "Order on the California Comprehensive Market Design Proposal" ("July 17 Order"). In its July 17 Order, the Commission, *inter alia*, rejected the CAISO's interim RUC proposal and directed the CAISO to expedite implementation of the integrated Day-Ahead Market, Ancillary Services market reforms and proposed reforms to the Hour-Ahead and Real-Time markets. Specifically, the Commission directed the CAISO to implement these Phase II reforms by January 1, 2003. The Commission also directed the ISO to make a compliance filing to implement the January 1, 2003 reforms by October 21, 2002. Finally, the Commission authorized the CAISO to expend funds for the development of LMP and the full network model, but determined that the specifics of implementation of those elements should be addressed in the technical conferences established by the July 17 Order.

On August 16, 2002, the ISO filed a request for rehearing of the July 17 Order in which the ISO requested, among other things, that the Commission grant rehearing of its requirement that the ISO implement the integrated Day-Ahead market and other Phase II market reforms by January 1, 2003. The CAISO argued that, given the significant number and extent of the changes to the CAISO's and market participants' software and systems and the scope of testing that must be undertaken to ensure proper functioning, a more prudent and rational approach would be to implement the aforementioned Phase II elements by May 1, 2003. The ISO continues to believe that this is the most reasoned and feasible time line, especially given the number of issues raised by stakeholders at the August 13-15 technical conferences that must be resolved in order to implement these changes, the expressed intention of the Commission to ensure an adequate stakeholder process for resolving these issues, and the fact that the Commission is not likely to issue an order on the October 21, 2002 compliance filing on the Phase II elements until late December 2002.

Pursuant to the July 17 Order, the Commission Staff convened a technical conference in San Francisco on August 13-15, 2002. Issues discussed at the MD02 Technical Conference included, *inter alia*, implementation of the MD02 Phases II and III proposals. At the MDO2 Technical Conference, the CAISO described the different stages of its MD02 implementation plan and set forth a realistic timeline for implementing the integrated Day-Ahead market and other Phase II market reforms. The parties spent a significant amount of time discussing the appropriate timeline for implementing the Phases II and III proposals and the market design elements that might be implemented in each Phase. At the end of the MD02 conference, the Commission Staff directed (1) intervenors to file comments regarding the CAISO's implementation proposal and the technical conference process going forward by August 23, 2002[2] and (2) the ISO to file reply comments by August 27, 2002. The instant Reply Comments address issues raised in parties' initial comments and set forth the CAISO's proposal for moving forward with MD02 implementation.[3] The CAISO notes that

[2] The following parties' comments on the August 13-15, 2002 Technical Conference have been posted on the Commission's FERRIS web site or otherwise obtained by the ISO: California Department of Water Resources State Water Project ("SWP"); California Municipal Utilities Association ("CMUA"); City of Santa Clara ("Santa Clara"); Dynegy Power Marketing, Inc., El Segundo Power, LLC, Cabrillo Power I LLC and Cabrillo Power II LLC (collectively, "Dynegy"); Energy Users Forum ("EUF"); Independent Energy Producers ("IEP"); Mirant Americas Energy Marketing, LP, Mirant California, LLC, Mirant Delta, LLC, and Mirant Portrero, LLC (collectively, "Mirant"); the Northern California Power Agency ("NCPA"); Pacific Gas and Electric Company ("PG&E"); Sempra Energy; Southern California Edison ("SCE"); and Williams Energy Marketing and Trading Company ("Williams").

[3] On August 19, 2002, the CAISO provided Market Participants with an "Overview of Implementation Efforts and Identification of Open Design Issues" ("Overview Paper"). Attachment B of The Overview Paper identifies four working groups that would be established to provide input

certain parties, in their comments, have taken positions regarding the merits of outstanding issues. The CAISO submits that such comments are beyond the scope of the comments requested by the Commission Staff and, as such, the CAISO will not address such comments in its Reply Comments.

II. REPLY COMMENTS

A. The CAISO Submits That The Phase II Implementation Timeline Originally Proposed In Its MD02 Filing And The CAISO's Request For Rehearing Is Preferable To Either An Accelerated Or Relaxed Implementation Process

Based on the concerns and preferences expressed at the MD02Technical Conference, the CAISO believes that there are three principal options for a revised MD02 implementation timetable. Option 1 would retain the original timetable proposed in the CAISO's May 1 and June 17 filings. Option 2 would be to accelerate some elements of Phase II in the spirit of the Commission's July 17 Order and establish a Day Ahead Energy market as quickly as possible. Option 3 would be to relax the Phase II timetable and combine Phase II with Phase III, so that the integrated forward markets would be implemented simultaneously with LMP and the Full Network Model in Fall 2003. Option 3 is based on the concern expressed by several market participants about having to prepare for two major market design changes if Phase II and Phase III are implemented separately. In this section, the CAISO explains why Option 1, the implementation timetable originally proposed and filed-for by the CAISO, is the best option.

Regarding Option 2, the CAISO was instructed at the August 13-15 Technical Conference to determine if it could accelerate the implementation of

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and resolve outstanding issues. Attachment C identifies open issues in this proceeding. A copy of some of the Phase II elements. The CAISO has determined, from a purely technical perspective, that it possibly could implement an hourly, integrated Day-Ahead Energy and Congestion Management market on a zonal basis (by eliminating the balanced schedule requirement and the market separation rule) and move the Hour-Ahead market closer to real time (hereafter referred to as the "Phase II Lite" elements) by January 31, 2003. The CAISO originally had proposed a Spring 2003 implementation date for these elements in the context of the complete Phase II.

The CAISO recognizes that Phase II Lite might be attractive to certain parties, *i.e.*, market participants who seek to eliminate the market separation rule and the balanced schedule requirement (*e.g.,* Dynegy, IEP, SCE, and Williams). Phase II Lite could provide some benefit for the CAISO. For example, elimination of the balanced schedule requirement might eliminate the long-standing incentive for Scheduling Coordinators to balance their portfolios by submitting load and generation schedules that ultimately bear little if any resemblance to actual real-time load and generation patterns. However, thus far there has been insufficient time for the CAISO to identify and analyze thoroughly all of the potential adverse impacts of implementing a Phase II Lite proposal.

Even though some parties might desire to accelerate implementation of the Phase II Lite elements, such enthusiasm necessarily must be tempered by the realities of what would be required to implement Phase II Lite on January 31, 2003. First, a number of issues fundamental to Phase II Lite (*e.g.,* whether or not the Hour-Ahead market should be retained, how to protect bilateral transactions

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the Overview Paper is attached hereto.

in the new energy market, and whether the new market should allow purely financial or "virtual" supply and demand bids) were identified by stakeholders as extremely important, but such issues have not yet been resolved because the stakeholder process is just now getting off the ground (see additional discussion of this below). These unresolved issues would have to be resolved **immediately** in order for the CAISO to meet a January 2003 implementation date for Phase II Lite and allow adequate time for market participants and the CAISO to design, specify, procure, and test the new systems and train personnel.[4] In short, it would be next to impossible to resolve the open issues in a timely manner through a deliberative process that provides all concerned parties with a meaningful opportunity to participate and vet the issues fully. The CAISO notes that, although several parties endorse accelerating Phase II, no party advocates an "accelerate at all costs" approach, nor does any party appear to value accelerated implementation of any feature of market redesign at the expense of not having a meaningful opportunity to participate in specifying the critical details of the market redesign via an open, deliberative process. For example, although Mirant and Williams support accelerating the implementation of a Day-Ahead market, they both indicate that implementing the new market design correctly is far preferable to merely implementing it quickly.[5]

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[4] The CAISO is concerned that Phase II Lite will create more problems for Real Time Operators. There may not be sufficient time to train market participants in CAISO operators adequately.

[5] While Mirant prefers that the CAISO implement its *integrated* Day-Ahead market on January 1, 2003, Mirant indicated that no parties' interests are served if the new Day-Ahead market is not correctly implemented at the outset. Mirant at 2-3 (emphasis added). The CAISO agrees with Mirant that no parties' interests are served through an incorrect implementation of

Second, Phase II Lite does not resolve many of the CAISO's operational concerns because, given the implementation timetable, it would only entail a simple hour-by-hour energy clearing and congestion management procedure, rather than the 24-hour optimization that would be implemented in the full Phase II. Running 24 separate hourly markets has a number of severe disadvantages compared to a 24-hour optimization. For example, it would not provide for feasible inter-hour ramping schedules because each hour would be cleared independently of all others. Furthermore, Phase II Lite does nothing to address the expressed concern about accommodating the technical constraints of resources, such as energy and emissions limitations and minimum run time (which is relevant for both load and generation resources). Finally, running 24 independent hourly energy markets instead of a 24-hour optimization would lack a rational unit commitment procedure for the next day and could often result in extremely inefficient use of long-start-time and other resources that require Day Ahead commitment decisions. Thus Phase II Lite would not provide any additional assurance to CAISO operators that Day Ahead schedules will a reliable predictor of real-time energy flows, and may ultimately yield more complexities than benefits.

MD02. The CAISO also notes that it cannot implement a fully integrated (*i.e.,* simultaneous Energy and Ancillary Services procurement) Day-Ahead market on January 31, 2003. The most the CAISO believes it can implement by that date is an hour-by-hour zonal Energy and Congestion Management market. Williams indicates in its comments that "the end result [of the Technical Conference] was an apparent group realization that, while the operation of [D]ay-[A]head market by January 1, 2003 is desirable, a well designed and functioning long-term market is more desirable." Williams at 22-23.

Third, implementation of Phase II Lite would in no way alleviate the concerns about having two major market design and software changes in 2003 for the CAISO and market participants.

While some market participants advocate accelerating the development of the Phase II elements, other market participants advocate the opposite approach identified as Option 3 above *, i.e.,* to delay any Phase II implementation until Phase II and Phase III elements can be combined and implemented together in Fall 2003.[6] As parties indicated at the technical conference, implementing Phase II and Phase III together in Fall 2003 would provide for a more thorough process to resolve the myriad of unresolved issues, would avoid the inefficiencies and "stranded" effort associated with a two-step implementation process, and would provide for adequate training for market participants on the operation of the comprehensive market design.

However, this approach would not provide the CAISO with adequate tools to address operational concerns during the summer of 2003. That is why the CAISO believes that the optimal approach is to implement the Phase II elements in Spring 2003 as originally proposed in the MD02 Filing (and discussed in greater detail in the CAISO's request for rehearing). In particular, the complete Phase II design (in dramatic contrast to Phase II Lite) offers substantial improvements to the CAISO's current market design that can significantly enhance market performance during summer 2003. These improvements derive from the fact that the full Phase II design entails a 24-hour optimization that will ensure feasible inter-hour ramping schedules, accommodate resource technical constraints such as limited energy and minimum run times, and efficiently commit units to serve the loads that clear in the Day Ahead Energy market. Thus, Phase II fixes the major existing design flaws that contribute to severe differences between Day Ahead schedules and actual real-time operation, thereby providing greater certainty for CAISO operators. In addition, the complete Phase II design would include integrated Ancillary Services procurement, which further enhances the efficient use of resources.

In further support of implementing the complete Phase II prior to summer 2003, The CAISO submits that the benefits of eliminating the market separation rule and the balanced schedule requirement are additional reasons why Phase II needs to be implemented prior to the Summer of 2003. The balanced schedule requirement has had severe real-time operational consequences through its incentives for market participants to schedule loads and resources at levels that differ dramatically from actual real-time performance. The market separation rule places constraints on the CAISO's congestion management procedures that reduce the efficiency allocation of congested transmission facilities. Having suffered along with the market participants through the problems caused by the market separation rule and the balanced schedule requirement, the CAISO strongly believes that the improvements that result from elimination of these requirements must be in place before Summer 2003.

In summary, the CAISO believes that the operational and market efficiency benefits of implementing Phase II prior to summer 2003 clearly outweigh the concomitant costs and challenges. In addition, while the CAISO

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[6] See, *e.g.,* SWP at 2-3; Sempra at 2; SCE at 3.

acknowledges that greater effort will be required of all parties to prepare for two major market and software changes during 2003, the CAISO also believes that phased implementation offers substantial benefits by allowing market participants to become familiar with the operation of the integrated forward markets on the familiar network infrastructure of the zonal model, prior to having to engage all the complexities of LMP, the Full Network Model and the redesigned Firm Transmission Rights.

The CAISO is sensitive to market participants' concerns about the inefficiencies of a staged implementation. However, the CAISO nonetheless believes that the staged implementation[7] proposed in its MD02 Filing strikes the proper balance between (1) moving forward quickly and moving forward carefully, (2) the desire to correct existing market inefficiencies and resolve certain operational problems before summer 2003, and (3) the desire to minimize the number of times that the CAISO will implement new software modifications. Accordingly, the CAISO urges that implementation of Phases II and III proceed on the CAISO's proposed timeline and that implementation of Phase II Lite and consolidation of Phases II and III be rejected.

B. The CAISO Supports The Proposed Working Group Process for Resolving MD02 Issues.

Given the large number, the broad scope and the significance of the unresolved issues and the likelihood that these issues cannot be addressed

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[7] PG&E, the largest load-serving entity in the ISO markets, also supports a staged implementation, noting "[a] phased[-]in approach may be beneficial as it is more conservative in implementing major market redsign in smaller steps that can be more easily corrected, if needed, than a large scale system change." PG&E at 5.

effectively or efficiently in large-group meetings with more than a hundred participants, the CAISO, in its Overview Paper, proposed creating four stakeholder working groups to address and hopefully resolve outstanding issues. The CAISO notes that there was clear consensus at the MD02 Technical Conference for a working group approach to resolve outstanding issues. The proposed working groups are:

1. Long-term Resource Adequacy-- This group would address the issues raised in the CAISO, State Interagency Working Group, and Reliant proposals. [8]
2. Integrated Forward Markets-- This group would address the elimination of market separation, integrated forward congestion management, energy market, Ancillary Services procurement and unit commitment, provisions for bilateral schedules and related issues.

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[8] Sempra requests that a Resource Adequacy requirement to be implemented in Fall 2003. Sempra at 3. IEP requests that an interim Resource Adequacy requirement be implemented as early as the first quarter of 2003. IEP at 3. Mirant proposes that all parties should develop and file a consensus Resource Adequacy proposal by December 31, 2002, and if no consensus can be reached, that parties be permitted to file competing proposals January 31, 2003. Mirant at 3-4. While the CAISO agrees that Resource Adequacy is an integral component of any successful market design, the CAISO does not support these proposals. First, the CAISO notes that the resource adequacy issues are extremely contentious. Second, as the CAISO pointed out in its MD02 Filing, it is unclear that the creditworthiness problems that have plagued two utilities in California will be resolved in a timely manner so as to permit the utilities to procure long-term supplies within the time frame proposed by certain parties. Resource Adequacy is an important issue that cannot and must not be dealt with in an interim and "knee-jerk" manner. The success of the new market design depends on the competitiveness of the new markets, and the competitiveness of the new markets depends on a well-designed resource adequacy requirement applicable to creditworthy load serving entities. The issue of resource adequacy should be vetted in the appropriate working group, and that working group should be given every opportunity to reach a consensus resolution of the issue.

3. Locational Marginal Pricing (LMP) and Firm Transmission Rights (FTRs)-- This group would address the full network model, nodal pricing, load aggregation, FTR design and allocation, and treatment of Existing Transmission Contracts.
4. Interim Provisions -- This group would address issues related to the market framework that will exist between now and the implementation of Phase II in spring 2003, including certain Phase I items such as real-time economic dispatch, moving the Hour-Ahead market closer to real-time and unit commitment.

The CAISO proposed that a sponsor from each class of market participants be designated to "lead" each working group and handle the logistical and organizational responsibilities of the group and facilitate meetings. The CAISO further proposed that each working group establish a charter that would define the scope of the group's activities and the guiding principles by which the group would develop its work product.

Williams has requested that the Commission direct the CAISO to make a compliance filing detailing (1) a collaborative process between the CAISO and stakeholders (and/or their technical experts) and (2) a binding schedule that accomplishes, in an expedited manner, the development of an SMD-compatible, fully integrated, security constrained, economic dispatch LMP market for the ISO. Williams at 23. SWP similarly suggests that the proposed working group process is "highly prescriptive" and the CAISO should solicit but not dictate stakeholder input. SWP at 4-5.

The CAISO, along with numerous other parties that submitted comments, is committed to the working group process and believes that the working group process satisfies Williams' request for a specified collaborative process. The CAISO also believes it is the responsibility of each working group to define the working groups' process and schedule.

However, the CAISO agrees with Williams that a schedule needs to be established to ensure that all market reforms can be implemented in a timely manner, while recognizing that it is important that all such reforms be done properly. While the CAISO, as a participant in each working group, can help inform and shape the process and schedule, it is not the CAISO's role to dictate each working group's process and schedule. Further, the CAISO must define a schedule based on implementation dates and must be able to proceed with the design as filed if no acceptable stakeholder consensus is reached on alternative approaches.

Sempra, while supporting the working group proposal, does not support the idea that certain parties should "sponsor" the working groups. It appears that Sempra is concerned that some sponsors might exert undue influence on the activities of the working group. The CAISO proposed the concept of working group sponsorship for the sole purpose of equalizing the logistical burden and costs of securing meeting locations and organizing meetings. In that regard, the CAISO alone should not have to bear the logistical and cost burden of sponsoring the working group process, particularly given that numerous parties already object to the level of the CAISO's GMC charges. The CAISO did not intend that the working group sponsors would control the groups' activities. All parties are entitled to participate in each and every working group. Accordingly, parties should be in a position to monitor the actions of working group sponsors. If parties believe that any particular sponsor is exerting undue influence on a working group, they should - and must – make such concerns directly known to the Commission and the CAISO, so that appropriate action can be taken.

Sempra proposes that each working group should employ the services of one or more technical experts with established credentials – all of whom should be retained and paid by the CAISO. While the CAISO would support the involvement of such experts in the working groups, the CAISO, does not support taking on sole responsibility for retaining and paying such consultants, particularly given that many of the parties to this proceeding already complain that the CAISO's costs are too high. Moreover, the CAISO is concerned that the process of identifying and retaining appropriate consultants, particularly ones who would have a consensus of support among stakeholders, represents a significant allocation of time and effort and would likely delay the initiation of substantive work by the working groups.

PG&E proposes to establish a fifth working group on Market Mitigation and Validation. While the CAISO does not oppose this fifth working group (and recognizes that there may need to be to add additional working groups in the future), the CAISO notes that parties' resources will already be spread thin by participating in four working groups, and this problem will only be exacerbated by the creation of a fifth working group. The CAISO believes that market mitigation issues can adequately be addressed in a more focused way within the confines of each of the four proposed working groups. Specifically, each working group can address market power and mitigation issues related to the specific market design changes they are addressing. For example, it might be appropriate for the LMP working group to examine local market power issues and the resource adequacy working group to examine market power issues in connection with the capacity market.

As a final matter, the CAISO notes that, at the meeting of the resource adequacy working group in Sacramento on August 23, 2002, certain parties raised concerns about the confidentiality of statements made and documents generated during the working group process. In the CAISO's opinion, the working group process is somewhat akin to a settlement process in an ongoing proceeding, and statements made, positions taken and documents generated during such working group process should be privileged and confidential.[9] The CAISO proposes that all persons involved in the working group process execute a confidentiality agreement. This will permit all stakeholders to participate freely and openly, thereby facilitating collaboration between all market participants.

C. The CAISO Has The Sole Right To Determine The Subject Matter Of Its Section 205 Filings

Dynegy objects to the statement in the Overview Paper that "in order to ensure that we move forward in a timely manner, absent any clear consensus

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9 . Sempra suggests that the CAISO utilize the NYISO's stakeholder advisory process in the working group context. The CAISO notes that the NYISO process generally precedes a NYISO filing. In this instance, there is an ongoing Commission proceeding. Thus, the instant circumstances are more akin to a settlement process than a stakeholder process.

resolution to an ‘open issue’, the ISO’s position is that its originally filed proposal would stand.” Dynegy Comments at 2. Dynegy argues that the Commission should require the CAISO to set forth the various positions that have been developed by the parties and re-file for Commission approval all open issues prior to implementation. IEP suggests that if specific working groups cannot reach a consensus position, then the working groups should present a summary of positions concerning particular proposals and the CAISO, like every other party, should advocate its position before the Commission. Similarly, Mirant suggests that if parties cannot reach a consensus regarding resource adequacy by December 31, 2002, then parties should file competing resource adequacy proposals by January 31, 2003.

Dynegy, IEP and Mirant ignore a basic tenet of regulation under the Federal Power Act, *i.e.,* the regulated utility **alone** has the right to initiate a Section 205 tariff filing and determine the appropriate content such Section 205 filing. *See Atlantic City Electric Company, et al. v. FERC,* 295 F. 3d 1 (D.C. Cir. 2002). The CAISO has filed its MD02 proposal pursuant to Section 205, and the Commission has directed that such proposal be evaluated in the technical conference process and ruled on in a future Commission order addressing such proposal. To the extent the parties reach a consensus on certain issues that is reasonable and feasible, the CAISO will amend its MD02 Filing. To the extent no consensus is reached on an issue, the CAISO cannot be required to submit other parties’ proposals for consideration by the Commission pursuant to Section 205. Further, the Commission cannot consider other parties’ separate and distinct proposals and approve any alternative proposal simply because the Commission deems such alternative proposal to be "better" than that proposed by the CAISO. To do so would usurp the CAISO's prerogative under Section 205 (as affirmed in Rule 205 of the Commission's Rules of Practice and Procedure) to file tariffs and associated practices "by and for" itself. If no consensus is reached on a particular issue, the Commission, consistent with the requirements of Section 205, should assess the justness and reasonableness of the CAISO's proposals based on the record developed in this proceeding.

III. CONCLUSION

Wherefore, for the foregoing reasons, the CAISO requests that the Commission (1) approve the CAISO's proposed implementation timeline for Phases II and III, and (2) approve the working group process identified in the Overview Paper.

Respectfully submitted,

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Filed: August 27, 2002

California ISO

Market Design 2002

- Overview of Implementation Efforts and Identification of Open Design Issues -

Purpose

The ISO offers this document as a means to inform the forthcoming FERC-directed Market Design 2002 (MD02) stakeholder process. In order to facilitate those discussions, the ISO believes that it is appropriate to: 1) clearly outline and articulate the ISO's implementation plan and efforts regarding those elements of the MD02 proposal approved by FERC in its July 17 Order; and 2) identify the issues that must be resolved in order for the ISO to implement the MD02 proposal in an appropriate and timely manner.

Throughout the body of this document the ISO has identified "open issues" in order to identify and catalogue issues that require resolution. It is important to clarify that "open" issues include both: 1) elements of the ISO's MD02 proposal on which market participants have raised substantive concerns; 2) issues or details not specifically addressed in the ISO's proposal. Please note that, with respect to the issues under (1) above, the ISO has identified that issue as "open" in recognition of market participant comments/concerns regarding that issue and as a result of the discussion at the August 13-15th FERC Technical Conference. However, in order to ensure that we move forward in a timely manner, absent any clear consensus resolution to an "open" issue, the ISO's position is that its originally filed proposal would stand.

Contents

The body of this paper provides a high-level overview of the elements of each phase of the ISO's MD02 proposal, the current timeline and status of the ISO's implementation efforts regarding each of the elements, and the design issues that must be resolved before the ISO can proceed further with its implementation efforts.

Attachment A provides an overview of the ISO's current MD02 implementation timeline (major components)

Attachment B contains a "strawproposal" regarding the formation of specific working groups to resolve all outstanding issues. The paper also makes recommendations on the form and function of those working groups.

Attachment C contains a *DRAFT* consolidated “open issues” list, listed by phase (e.g., Phase I, Phase II, and Phase III). This list can be resorted to reflect the final working group structure.

Background

The MD02 Filing

On May 1st and June 17th, 2002, the ISO filed a comprehensive market design proposal and related tariff language. As outlined in the ISO’s May 1 and June 17 MD02 filings, the ISO proposed to implement its design proposal in the following three distinct phases:

Phase I

In Phase 1 (most of the elements of which were contemplated to be effective on October 1, 2002 when the current Commission-ordered price mitigation provisions are due to expire),[10] the ISO proposed to implement:

- Local Market Power Mitigation;
- Interim Residual Unit Commitment (“RUC”);
- Modified Must Offer Requirement;
- Real-Time economic dispatch;
- Use of a single Energy bid curve;
- Penalties on generators that fail to comply with dispatch instructions;
- Extension of the Commission’s current market mitigation measures;
- A rolling 12-Month Competitive Index, including pre-authorized Mitigation; and
- A price cap on negative l bids.

In addition to the above the ISO presented an alternative price mitigation proposal, should the Commission decide not to extend the current price mitigation measures. This alternative proposal consisted of a damage control bid cap of $108/MWh and Automatic Mitigation Procedures (“AMP”) to prevent economic withholding. Together, the above elements and alternatives were categorized by the ISO as “the October 1 Elements.”

Phase II

For Phase 2 of MD02, the ISO set a target date of Spring 2003, and stated that by that time it would be able to implement:

[10] Local Market Power Mitigation was proposed to be effective on July 1, 2002.

- The integrated day-ahead and hour-ahead markets (to include simultaneous energy, congestion management, ancillary services and unit commitment);[11]
- A permanent Residual Unit Commitment procedure that would operate for reliability purposes after the day-ahead and hour-ahead markets;
- Elimination of the Market Separation Rule and the balanced schedule requirement in the Day-Ahead and Hour-Ahead Markets;
- Moving the time line for the Hour Ahead Market closer to Real Time; and
- Transitional release of Firm Transmission Rights ("FTRs") in accordance with the ISO's current design, to cover the interim between when the current FTRs expire and the new FTR structure is in effect in Phase 3.

Phase III

For Phase 3, the ISO set a target date of Fall 2003/Winter 2004, and explained that by then it would be able to complete the final elements on MD02, including:

- The detailed network model and full implementation of Locational Marginal Pricing (LMP) at the nodal level in the Day-Ahead, Hour-Ahead and Real-Time Markets;
- The redesign of FTRs to be consistent with LMP; and
- An available capacity ("ACAP") obligation on Load Serving Entities.

As noted above, the completion of Phase 3, and thus of the comprehensive MD02 design, requires the shift to a nodal pricing structure, rather than the current zonal system, and thus will require extensive software and systems development. For this reason, the ISO provided time to complete these tasks before roll out of the complete MD02 structure.

The July 17th Order

The July 17th Order accepted certain aspects of the ISO's proposal and authorized the ISO to proceed with implementation of those elements. Table I below summarizes FERC's actions.

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[11] To be implemented at this point using the existing three-zone network model, until the nodal pricing structure is completed in Phase 3.

Table I

Summary of MD02 Proposal and FERC Action		
MD02 Element	**FERC Action**	**Effective Date**
Phase I		
Damage Control Bid Cap – The damage control bid cap (DCBC) is equal to the higher of $108/MWh or a price established by the product of the highest heat rate unit and a monthly gas index price.	Rejected and established a "hard' cap of $250/MWh.	October 1, 2002.
Automatic Mitigation Procedures (AMP) – Automatic price mitigation based on threshold price and impact tests.	Accepted AMP but established price screen floor of $91 and revised price and impact screens	Later of October 1, 2002 or date when Independent Entity provides Reference price information.
Local Market Power Mitigation	Incorporated local market power mitigation into AMP.	Effective date of AMP – Later of October 1, 2002 or date Independent Entity provides Reference Prices.
Interim RUC - Interim Residual Unit Commitment ("RUC")	Rejected. Directed continuation of existing ISO Must-Offer waiver policy.	N/A.
Must-Offer - Modified Must Offer Requirement;	Extended existing West-wide Must-Offer Obligation.	Currently effective.
Economic Dispatch - Real-Time economic dispatch;	Accepted, subject to availability of supporting and additional outage reporting and multiple ramp-rate accommodating software.	When software complete **and** when ISO's extended SLIC software available. (Current projection – 1/03). ISO believes that Economic Dispatch and Penalties on Uninstructed Deviations should be implemented together.
Single Energy Curve - Use of a single Energy bid curve	Accepted, subject to availability of supporting and additional software.	October 1, 2002, when AMP becomes effective.
Penalties on Uninstructed Deviations - Penalties on generators that fail to comply with dispatch instructions;	Accepted, subject to availability of supporting outage reporting and multiple ramp-ratesoftware.	When software complete **and** when ISO's extended SLIC software available and ISO software is able to accommodate multiple ramp rates. (Current projection – 1/03).
Extension of FERC Mitigation - Extension of the Commission's current market mitigation measures.	Rejected – Extended existing Must-Offer and elements of ISO's alternative proposal.	N/A.

12-month Index - A rolling 12-Month Competitive Index, including pre-authorized Mitigation	Rejected as price mitigation tool but accepted as reporting/tracking tool.	October 1, 2002, as part of weekly reporting requirement.
Decremental Price Cap - A price cap on decremental bids.	Accepted, but as a "soft" cap, where suppliers could seek to justify costs in excess of the cap.	October 1, 2002.
Phase II		
Integrated Market – The integrated day-ahead and hour-ahead markets (to include simultaneous energy, congestion management, ancillary services and unit commitment)[12]	Accepted proposal to establish integrated market.	January 1, 2003 (ISO had proposed May 1, 2003).
Permanent RUC - A permanent Residual Unit Commitment procedure that would operate for reliability purposes after the day-ahead and hour-ahead markets.	Unclear. FERC stated that discussion of long-term resource adequacy will be set for technical conference.	Unclear. Perhaps January 1, 2003.
Market Separation - Elimination of the Market Separation Rule and the balanced schedule requirement in the Day-Ahead and Hour-Ahead Markets.	Accepted as part of integrated market.	January 1, 2003 (ISO had proposed May 1, 2003).
HA Timeline - Moving the time line for the Hour Ahead Market closer to Real Time.	Accepted.	January 1, 2003 (ISO had proposed May 1, 2003).
Transitional FTRs – Transitional release of Firm Transmission Rights ("FTRs") in accordance with the ISO's current design, to cover the interim between when the current FTRs expire and the new FTR structure is in effect in Phase 3.	Unclear.	Unclear.
Phase III		
Network Model and LMP - The detailed network model and full implementation of locational marginal pricing (LMP) at the nodal level in the Day-Ahead, Hour-Ahead and Real-Time Markets.	Accepted and subject of Technical Conference. Directed ISO to begin development and to expend funds.	Unclear. Fall 2003.
FTRs - The redesign of FTRs to be consistent with LMP.	Subject of Technical Conference.	Unclear. ISO had proposed Fall 2003.
ACAP - An available capacity	Subject of Technical	Unclear. ISO had proposed

[12] To be implemented at this point using the existing three-zone network model, until the nodal pricing structure is completed in Phase 3.

("ACAP") obligation on Load Serving Entities.	Conference.	January 2004.

The following sections highlight the ISO's implementation efforts and timeline for each of the three MD02 phases. In addition, the following sections also attempt to identify the major open or unresolved issues that must be resolved in order for the ISO to develop and implement the MD02 design in a timely manner.

Phase I

The Phase I design elements can effectively be broken into two categories. **Phase I A** includes all of the price mitigation measures: Damage Control Bid Cap, Negative Bid Cap, AMP, Local Market Power Mitigation, Single Energy Curve in the real-time market, and, as part of a weekly reporting requirement, the 12-month Competitiveness Index. **Phase I B** includes Real-time Economic Dispatch and Penalties on Uninstructed Deviations. In addition, as a result of the FERC order, implementation of the Penalties on Uninstructed Deviations is now dependent on the availability of the ISO's proposed enhanced SLIC application.

Phase I A

The DCBC and the Negative Bid Cap are easy to implement and, subject to no major unforeseen events, will be in place and effective on *October 1, 2002*.

The AMP and related software are more difficult to incorporate into the ISO's existing software. At present, the ISO intends to install the new AMP software on the ISO's existing software platform. The current estimate is that, with respect to AMP software integration, the ISO can integrate and test the AMP software by *October 1, 2002*. The biggest unknown or contingency with respect to AMP implementation is calculation of the Reference Prices by an independent entity. As noted above, FERC directed that the ISO issue an RFP for an independent entity to calculate the reference prices to be used by the ISO as part of the AMP. The ISO issued the RFP on Friday, August 9, 2002. Responses are due August 23, 2002. At this point, the ISO is unsure as to the next steps should there be no responses to the RFP or if the submitted bids are exorbitantly expensive.

Open Issue: Next Steps if there are no responses to AMP Reference Price RFP or if bids are exorbitantly priced.

The ISO also is concerned that the FERC-established AMP thresholds may not adequately protect customers from the exercise of market power under the current market conditions. The ISO believes that the California markets are not workably competitive.

Open Issue: Rehearing issue. The ISO will seek rehearing of the new FERC-established AMP thresholds.

The July 17 Order also established a new AMP price screen. Under the new screen, AMP will not apply if the market clearing price for all zones is \$91.87/MWh or less. The ISO is concerned that such a price screen will lead to an unjustifiable increase in prices in the California market. Moreover, the ISO believes the Commission based its decision on the erroneous conclusion that the New York ISO employs a similar price screen approach. The ISO believes that is incorrect.

> ***Open Issue: Rehearing issue. The ISO will seek rehearing of the new FERC-established AMP price screen test. To the extent that the Commission believes a price screen is necessary, the ISO believes a lower price screen is appropriate.***

As noted above, FERC rejected the ISO's stand-alone local market power mitigation proposal and instead directed the ISO to rely on existing cost-based Reliability Must-Run (RMR) Generation for local market power mitigation and, in instances where RMR is not available, to apply the AMP (bid will be mitigated if bid is \$50/MWh greater than market clearing price (MCP) or over 200% greater than MCP, but will not be mitigated if below \$91.87/MWh.) While these changes are not necessarily difficult to incorporate into the AMP and the new software, the ISO questions the propriety of FERC's actions. The ISO is not convinced that bids below \$91.87/MWh are not the product of local market power.

> ***Open Issue: Rehearing issue. The ISO has sought rehearing of FERC's order on the Local Market Power Mitigation. The ISO does not believe that FERC's directive adequately mitigates the exercise of local market power, either exhibited through the "DEC" game or through excessive incremental bids.***

> ***Open Issue: Clarification Issue. The ISO has sought clarification from FERC that FERC did not intend for the ISO to "decrement" Reliability Must-Run (RMR) Generation for purposes of managing Intra-Zonal Congestion. The ISO does not have the right or ability to "Dec" RMR units to manage Intra-Zonal Congestion.***

Finally, FERC directed the ISO to file the information produced by the 12-month MCI on a weekly basis with the Commission's office of market Oversight and investigation. The ISO intends to begin to comply with this directive as of *October 1, 2002*. The ISO is concerned that it may not be possible to produce such information on a weekly basis. The ISO currently utilizes information that is only available on, at best, a monthly basis to calculate the 12-month MCI. Thus, the ISO has requested that the Commission establish a monthly, rather than weekly, reporting requirement once the day-ahead market is operational or a bi-monthly requirements as long as the IOS must rely on CERS-provided data.

> ***Open Issue: Rehearing issue. The 12-Month MCI reporting requirement should be monthly, rather than weekly, once the***

integrated day-ahead market gets implemented and should be bi-monthly as long as the ISO has to rely on CERS data.

Phase I B

The Phase I B elements, real-time economic dispatch and penalties for uninstructed deviations, are permanent critical features of the new market design and should appropriately be built on the ISO's new software platform. Thus development of these elements will require integration and testing with the new platform. Moreover, such critical new market features will require thorough market participant testing and integration with their own systems. Finally, as noted above, FERC directed the ISO not to implement these new features until the ISO's new/enhanced "SLIC" (scheduling and logging program) and the interface between that program and the ISO's existing Outage Scheduler software is complete and until the ISO's master file software is able to accommodate multiple ramp rates. The ISO currently estimates that such software will not be available until January 1, 2003. in addition, the ISO believes there are certain unresolved issues with regard to the receipt, validation and incorporation of multiple ramp rate information for each unit.

Open Issue: How to calculate, validate and incorporate multiple ramp rate information for each generating unit.

Finally, FERC rejected the ISO's so-called interim RUC proposal wherein the ISO would permit imports (hydro) to bid into the ISO's commitment process. FERC stated that "the need to develop the CAISO's proposed interim residual unit commitment process is not critical at this time, despite the CAISO's assertions to the contrary." (July 17th Order at 43). FERC reasoned that because it was extending the current must-offer obligation, and expediting the development of other features proposed by the ISO, there were sufficient assurances that generators would make their uncommitted capacity available to the market. The ISO remains concerned about the propriety and efficacy of continuing with the current must-offer waiver process and not implementing the ISO's proposed interim RUC process.

Open Issue: Rehearing issue. FERC erred in not approving the ISO's Interim RUC process. The Must-Offer Obligation and RUC are complementary – Must-Offer to ensure generation is made available to the ISO in real time and RUC to commit such resources to satisfy forecasted load.

In addition, when rejecting the ISO's proposed Interim RUC process, FERC noted that the ISO currently used "Transmission Constrained Unit Commitment" or "TCUC" software to facilitate the existing waiver process and commit resources. That characterization is not entirely accurate. Although the TCUC software accommodates the "economic" commitment of resources, the ISO is not presently committing resources on an economic basis because previous FERC orders directed the ISO not to do so. Thus, the ISO has filed for clarification that, in the context of the existing Must-Offer Obligation and associated waiver process, the ISO is authorized to commit resources using its TCUC program, which employs a security-constrained, *least-cost* algorithm.

> ***Open Issue. Clarification Issue. The has filed for clarification from FERC that, in the context of the existing Must-Offer obligation and the associated waiver process for committing resources, the ISO can use its TCUC program, which employs a security-constrained, least-cost algorithm.***

Phase II

Integrated Forward Energy Market

Phase II primarily provides for the establishment of an integrated day-ahead and hour-ahead market. The function of the integrated forward market would be to simultaneously optimize the procurement of energy and ancillary services and to manage transmission congestion. As proposed by the ISO, the Phase II integrated market would still be a zonal market. That is, while the ISO will calculate nodal energy prices using the new integrated-market optimization (OPF) program (that will eventually become the basis of nodal or LMP pricing in Phase III), the ISO will continue to publish and price energy and transmission based on the existing zonal model. Thus, the ISO will develop, based on the weighted average of the nodal prices generated by the new optimization program, zonal energy prices and will continue to manage and price transmission for each of the existing Inter-Zonal paths. In addition, Intra-Zonal Congestion will also continue to be managed as it is today – allocating those costs, as an uplift, to load within each of the zones. Without question, development and implementation of the integrated market will be a significant challenge. Even under the ISO's originally proposed timetable (integrated market effective around May 1, 2003), the ISO believes it will be hard pressed to meet that date. Thus, FERC's directive to implement the new integrated zonal market by January 1, 2003, is particularly challenging. In particular, the ISO is concerned that such a timeline will not allow for sufficient integration and market participant testing, including the necessary development of each market participant's own supporting systems. The implementation of the new integrated market is a complete paradigm shift for participants in the California market and will require extensive "reeducation" and training. As summarized in Attachment A, under the ISO's aggressive Spring 2003 implementation date, the ISO would have to finalizing the design details of the integrated forward market by the end of *August, 2002* in order to proceed with the detailed specification work. Thus, in order to meet FERC's directive for a January 1, 2002, implementation date for the integrated forward market, all design issues should have been resolved by the July 17 Order, or earlier. As detailed below, such is not the case.

> ***Open Issue: Rehearing Issue. The ISO will seek rehearing of FERC's directive to implement the new Phase II integrated zonal market by January 1, 2003. The ISO does not believe that the expedited schedule established by FERC is feasible***

and will not allow for proper system integration and testing (See also next issue).

Moreover, a number of market participants have raised concerns about proceeding with two significant market design changes (Phase II and Phase III) within 6-9 months of each other. Thus, many market participants have recommended collapsing Phase II into Phase III and only implementing one significant market change in the Fall of 2003.

Open Issue: Should the ISO consolidate Phase II and Phase III of the MD02 proposal and implement the forward integrated market with LMP pricing beginning in the Fall of 2003?

As proposed in the MD02 proposal, Phase II provides for the establishment of an integrated day-ahead and hour-ahead energy/ancillary services/transmission market. Certain market participants have raised concerns that by facilitating day-ahead, hour-ahead and real-time markets (as well as markets for energy, various ancillary services, and transmission), the ISO's markets would be subject to manipulation. Furthermore, in support of these arguments, these market participants note that FERC's SMD only proposed day-ahead and real-time markets.

Open Issue: Should the ISO's MD02 proposal include a hour-ahead energy market?

In addition, consistent with the existing market design, the ISO had proposed that its integrated market entertain or permit both *physical* and *financial* trades. That is, market participants would be able to submit both bids that are tied to a physical resource and bids that are strictly financial, where a market participant is taking a financial position in the market. Certain market participants have raised concerns that the ISO should not permit financial or "virtual" bids in its markets. Other market participants state that the ISO should, at a minimum, require that financial or virtual bids be clearly identified or "flagged." Such a requirement is consistent with the requirements proposed in FERC's Standard Market Design NOPR.

Open Issue: Should the ISO permit the submission of financial or "virtual" bids in its day-ahead and hour-ahead markets? (i.e., let such transactions take place outside – bilateral/third-party facilitated - of the ISO's markets, which, certain participants believe, should be primarily physical)

Open Issue: Should the ISO "stage" implementation of a "financial" market?

Open Issue: Should the ISO require that all financial or "virtual" bids be clearly identified or "flagged"? If so, who should be able to see such a "flag"?

Open Issue: What are the cost implications of facilitating "financial" trades? Is it worth it?

In the context of facilitating a forward energy/AS/transmission market, a number of participants have inquired as to how they can schedule or protect bilateral transactions and their related schedules. Although the ISO believes that its proposed integrated market clearly provides for and supports such transactions, this requires further explanation and training.

> ***Open Issue: How can bilateral transactions/schedules be submitted and "protected" under the ISO's proposed market design?***

Resource Commitment Processes

Finally, many market participants have raised concerns and questions regarding the details and development of the ISO's resource commitment procedures, both in the context of the integrated markets *security-constrained unit commitment (SCUC)* process and with respect to the *Residual Unit Commitment (RUC)* process. First, a number of participants have questioned the need for any formal unit commitment procedures and assert that the ISO should instead rely on existing capacity markets, such as Replacement reserves, in order to ensure that sufficient capacity is on-line to meet the next day's forecast load.

> ***Open Issue: Should the ISO rely on its existing Replacement Reserve market instead of a new SCUC/RUC process in order to ensure that sufficient capacity is committed in the day-ahead market to satisfy the next day's forecast load?***

> ***Open Issue: What type of mechanism should the ISO utilize in the near-term/interim to commit resources until a long-term resource adequacy and commitment process are in place?***

Second, a number of participants fail to understand the relationship between SCUC/RUC and long-term resource adequacy. As previously explained by the ISO, the ISO believes the existing Must-Offer Obligation and, eventually, a long-term resource adequacy mechanism, are means to ensure that resources are *available* to the ISO, whereas SCUC and RUC are *"tools"* for committing resources once those resources have been made available to the ISO for commitment. However, the ISO recognizes that it must further explain this interrelationship.

> ***Open Issue: Explain relationship between SCUC/RUC, capacity adequacy and physical withholding? How to prevent physical withholding in both the short-term and long-term)?***

In addition, a number of market participants have raised concerns that whatever short-term measures are adopted, these measures should not create obstacles to implementing an effective long-term resource adequacy and resource commitment process. Moreover, such interim measures should create appropriate incentives for both load and generation to act appropriately and be balanced with established price mitigation measures.

Open Issue: Near-term or interim market structure (esp. commitment procedures) should not create obstacles to the implementation of effective and fair long-term resource adequacy and commitment procedures.

Open Issue: Suppliers want whatever near-term/interim commitment process is established to be compensatory (i.e., include a capacity payment).

Open Issue: Market participants want to ensure that commitment process and compensation appropriately recognizes and reflects effective price mitigation (i.e., that price mitigation measures do not prevent or inhibit cost recovery (especially from limited run-time resources) and that effective measures to prevent physical withholding are in place).

Open Issue: Suppliers want to ensure that interim market structure and commitment process does not create an incentive for load to under-schedule and rely on ISO cost-based commitment procedures.

In addition, market participants have raised concerns regarding the details of the ISO's proposed SCUC and RUC processes. For example, certain market participants believe that the start-up and no-load bid components of the ISO's proposed integrated market (including SCUC and RUC processes) should be market based, as opposed to cost-based, as proposed by the ISO.

Open Issue: Should start-up and no-load bid components of integrated market be cost-based or bid-based? How often should market participants be permitted to change these values?

In addition, market participants want the ISO to clarify whether the ISO intended to propose a "minimum-load" (i.e., producing a minimum amount of energy) bid component as opposed to a "no-load" (i.e., producing no energy but synchronized to the grid) bid component and if so, why?

Open Issue: Is the ISO proposing to accept "minimum-load" bids or "no-load" bids as part of its integrated market proposal?

Furthermore, suppliers, concerned about depressing energy prices both in real-time, recommend that minimum-load energy be paid the real-time market clearing price (as opposed to cost, as proposed by the ISO).

Open Issue: Should the ISO pay minimum-load energy the real-time market clearing price, as opposed to compensating suppliers at cost for such energy?

Finally, certain market participants were unclear as to how large curtailable load fits into and is impacted by the ISO's proposed RUC process. Specifically, these parties questioned how the RUC process accommodates the physical operating constraints (e.g., Energy Bids (Load cannot be "Inc"ed - go up), Ramp Rates / Min. Up/Down, etc) of large curtailable load-based resources.

> ***Open Issue: How does the ISO's proposed RUC process accommodate the physical operating constraints of large curtailable load-based resources?***

In addition, a number of participants asked how will the SCUC/RUC processes work with and impact energy-limited resources?

> ***Open Issue: How will the SCUC/RUC processes work with and impact energy-limited resources?***

General Issues

Many market participants asked a number of over-arching questions. First, and of utmost import to all market participants, was to gain a better understanding how settlements will work under the proposed market design.

> ***Open Issue: What are the settlements implications from moving to the new market design?***
>
> ***How are the costs related to each design element proposed to be allocated?***
>
> ***What price will be paid for each service?***
>
> ***What is the underlying cost-causation basis for each proposed cost allocation?***
>
> ***What is the impact on ISO systems and market participant systems?***

Market participants also raised the following specific questions:

> ***Open Issue: How does the MD02 proposal accommodate participation by energy-limited and load-based resources?***

and

> ***Open Issue: How are losses accounted for under the new proposal? How can losses be self-provided?***

Finally, almost every market participant requested that the implementation timeline and process accommodate the following:

> ***Open Issue: The ISO's implementation timeline and schedule should accommodate extensive market participant training.***
>
> ***Open Issue: The ISO should permit active market participant participation in developing and reviewing the detailed***

specifications of the ISO's market design to ensure that the detailed design and software is consistent with the high-level design and is not subject to manipulation.

Phase III

Authorization on Development of LMP and the Full Network Model

In the July 17th Order the Commission authorized the ISO to "begin expending funds on the development of software and systems for LMP and the full network model." (July 17th Order at 41). In support of this direction, the Commission stated that, "...initiating its [LMP] development as soon as possible will accelerate the implementation schedule for the long-term market design changes we believe are necessary to support a well functioning wholesale market." (Id). However, recognizing the concerns of certain market participants in transitioning to an LMP pricing regime, the Commission stated that it would not address the specific arguments of these intervenors in the July 17th Order and that, "The Commission believes it will be a more efficient use of all parties' resources to discuss the specifics of implementation as part of the technical conferences that we are establishing in this order."

In order to inform this discussion, the ISO offers its perspective on what it means to implement LMP using a full network model.

Network Model

In order to implement LMP, the ISO must develop a detailed network model representation of the ISO Controlled Grid. As a starting place, the ISO intends to work from the detailed network representation developed as part of the ISO's new Energy Management System (EMS). Once fully implemented, the new EMS will include the following network applications: State Estimator, on line power flow, and contingency analysis. As the Commission and most parties are aware, the ISO intends to implement the new EMS in two phases. Phase 1 (currently on-line) includes new System Control and Data Acquisition (SCADA), Automatic Generation Control (AGC), operating reserve calculation systems. Phase II of the EMS project provides for the development and implementation of a detailed network model and state estimator and is intended to be complete by end of 2002. In parallel with the completion of the EMS project the ISO will develop a detailed network *market* model that will be used to produce nodal prices. Consistent with the ISO's MD02 filings, such a model is anticipated to be available by Summer 2003 and on-line and effective by the Fall of 2003.

The following sections briefly summarize this phased development process.

<u>EMS Project Phase I – SCADA, AGC, Operating Reserves</u>

As noted above, the ISO installed and began to use its new EMS at the beginning of this year. The new EMS includes SCADA, AGC and contingency analysis tools and is performing as expected.

<u>EMS Project Phase II – Network Model and State Estimator</u>

Network Model

Development of the new EMS network model will start with a 30,000 bus "breaker" model that reflects the entire Western Electricity Coordinating Council (WECC) transmission system and can accurately represent the day-to-day topology (i.e., transmission map) of the interconnection. As part of Phase II of the EMS project, the ISO will develop a detailed representation of the California system (a 6-7,000 bus representation) and an "external equivalent" of the external WECC system. To develop the external equivalent the ISO will effectively take the 23-24,000 buses included in the non-California representation of the WECC system and develop a simplified representation of that system that would enable the ISO to assess the impact of transmission flows outside of California on the California system.

With respect to the representation of the California system, the ISO has already modeled the San Diego Gas & Electric Company (SDG&E) portion of the ISO Controlled Grid and the model is performing acceptably, although a number of issues still need to be resolved. The ISO is currently working on the Southern California Edison Company (SCE) portion of the model, which is almost complete. The ISO does not anticipate any major problems with modeling the primarily 230-500 kV SCE system in which sub-transmission lines typically do not underlie and parallel higher voltage transmission lines.

On the other hand, development of the Pacific Gas & Electric Company (PG&E) portion of the network model is likely to be more difficult. Because much of PG&E's sub-transmission network underlies and is parallel to PG&E's higher voltage transmission network, this requires that both networks be operated together. The facilities that comprise the PG&E portion of the ISO Controlled Grid range from 60 kV up to 500 kV. PG&E is in the process of developing lower voltage network models in order to represent generating units greater than 10 MWs and loads that are connected to their lower voltage facilities. Until this effort is complete, the ISO will be unable to assess the real-time status of these facilities and therefore will be unable to directly calculate nodal prices for the many generators and loads connected to these facilities. As more information is obtained with respect to the constraints in developing the PG&E portion of the model, the ISO will share such information with the Commission and all parties.

State Estimator

A state estimator is an application tool that enables grid operators to instantaneously assess the real-time status of the grid at places where real time measurement data does not exist based on measurable conditions at places on the grid where data does exist. The state estimator enables operators to determine the real-time flows on all networked transmission facilities and also enables the operators to assess the status of all generation and load on the system. Based upon such information, the operators can make accurate real-time adjustments to resources on the system and thereby balance generation and load and honor all known operating and thermal constraints on the system.

Thus, a well-functioning state estimator greatly enhances an operator's ability to reliably operate the system in real time.

Development of the Market Model

The market model to be used in calculating and determining nodal prices will be developed from the detailed network model developed as part of the Phase II of the EMS Project. Starting with 30,000 bus EMS state estimator model, the ISO will develop a network or market model that will be used for running the ISO's proposed forward integrated energy/ancillary services/congestion management market and the real-time market. The forward market model will include an external equivalent that represents the transmission system external to California.

As proposed by the ISO, the full network model will be used in the following six procedures:

1. Day-ahead simultaneous energy and A/S optimization (SCUC);
2. Day-ahead residual unit commitment (RUC);
3. Hour-ahead simultaneous energy and A/S optimization (SCUC);
4. Hour-ahead residual unit commitment (RUC);
5. Real time imbalance energy (SCED); and
6. FTR allocation and auction.

An outstanding issue with respect to the development of the model is how often to update the external equivalent to capture system conditions. Ideally, the model would be updated every hour in order to best represent system conditions. However, most existing models do not include such functionality. At present, the ISO is proposing to update the model about twice per year – both in winter and in summer. Should the ISO update the model only twice a year, it may be necessary to build the model so that it can capture the status of significant external transmission paths.

Open Issue: How often should the ISO's network model be updated to reflect changes in the external system?

Of course, in order for the market model to function properly, the ISO will have to map all load and generation from the EMS system to the market model. For forward-market application, the model will rely on market participant submitted preferred schedules and known generating unit and load characteristics and data, including updated generating unit availability information provided from the ISO's Schedule Logging ("SLIC" or "Outage Scheduler") application. In real-time, the model will rely on actual telemetered values from these resources or from projections of these values from the state estimator.

Locational Marginal Pricing (LMP)

As noted above, the July 17th Order specifically authorized the ISO to expend funds and begin the development of LMP. As is well known, LMP is the basis of the ISO's proposed forward and real-time integrated markets. What is LMP pricing? Quite simply, it uses the locational specificity of the detailed network model described above to determine a location-specific price for energy produced at or consumed at that location. The locational marginal price or LMP is the cost to produce or consume one additional MW at that specific location. Implicit in that energy price is the cost of congestion between two different locations and the losses associated with that location. Thus, if there was congestion on the transmission lines that connected two locations or "nodes" on the system, the cost of managing that congestion (i.e., the cost of redispatching resources as a result of that congestion) would be reflected in the energy prices.

What are the basic inputs necessary to generate locational marginal prices? The ISO proposes to use a security-constrained optimal power flow program (OPF) to calculate LMPs. A security-constrained optimal power flow program determines the least-cost way to serve load while respecting network constraints. As stated in the ISO's MD02 filing, the ISO proposed to develop a AC OPF, which, in addition to respecting power flow constraints, would respect voltage constraints, for determining LMPs. It is the ISO's understanding that the NYISO uses such a OPF, while the PJM Interconnection uses a DC OPF.

Open Issue: Should the ISO develop and utilize a AC or DC OPF for calculating LMPs?

Aside from resolution of this issue, the basic components of the OPF are: 1) the engineering or factual data related to operation of the system; and 2) the bid data and schedules submitted from market participants. Based on these inputs, the OPF will solve for a solution that both honors the known and modeled engineering/factual constraints and, as described further below, the cost-minimization objective function of the OPF.

Engineering/Factual OPF Inputs

In order to generate locational marginal prices there must be a market model that accurately depicts or represents the transmission network topology (i.e., a detailed electrical map of the system that identifies the location or "node" for which prices are to be calculated). This is the detailed network model described in the ISO's MD02 filing. As described above, the ISO proposes to develop such a network model based largely off of the network model in the ISO's EMS. The network model and algorithm must represent the thermal and voltage constraints on the system and must also include the nomogram constraints that must be honored to ensure reliable grid operation.

As was discussed extensively in the ISO's earlier Congestion Management Reform (CMR) process, ISO operators use a set of around twelve nomograms to reliably operate the system on a day-to-day basis.[13] Nomograms effectively define the relationship between generation, load, voltage and system stability in certain areas. More specifically, nomograms look at the most constraining of thermal limits, voltage security/voltage stability limits, and inertial stability limits, while considering N-1, and where relevant N-2, contingencies. Thus, ISO operators are able to ensure, based on known or projected load levels, that sufficient generation is on line in certain areas in order to maintain voltage support and system stability. In a nomogram, voltage & stability constraints are linearized for representation as a graph or an equation. At present, the ISO anticipates that these nomogram constraints will be set manually based on expected system conditions (i.e., the functionality of the programs may not allow the nomograms to be automatically updated). However, recognizing that certain programs do automatically update nomograms, the ISO may incorporate this feature into its design. Finally, to the extent not captured in the nomograms, the ISO may also need to account for certain contingencies in the network algorithm.

Open Issue: Should the ISO design its network model so that nomogram constraints can be updated automatically or should such constraints be set manually?

The market model must have contain or have access to resource information/attributes (e.g., maximum generating unit capability (Pmax), generating unit ramp rates, updates from the ISO's SLIC application, etc.). All of this information, as well as the network topology effectively defines the universe of known factual data from which the ISO runs the market model. In other words, this information is necessary, in the context of running the market model, for identifying the theoretically infinite number of possible operating points that satisfy the operating and reliability constraints modeled in the market models algorithm. Cost and bid data are not relevant to this solution.

The OPF Objective Function

How are the energy prices calculated? The energy prices at each location will be determined from a optimization algorithm or program that considers the engineering criteria outlined above, as well as cost and bid data. Thus, the optimization determines a solution that both satisfies the engineering constraints (criteria) and the minimum-cost objective function proposed by the ISO.

When determining forward-market LMPs, the "Base Case" optimization would consider the defined network topology (network model, including updated nomograms), the resource (generation and load) attributes from the ISO's "Master File", as updated from SLIC, the preferred operating points of resources as indicated in market participant preferred schedules, and the bids submitted by market participants (start-up, minimum load, energy curve, AS capacity). The ISO proposes that the start-up and minimum load components be cost-based

[13] The ISO anticipates that certain of the existing nomograms may not need to be incorporated in to the LMP model because they primarily address thermal constraints and such constraints will already have been incorporated into the network model.

and that the energy and capacity components be bid-based. A number of market participants have raised concerns with this proposal

Open Issue: Should the optimization objective function also include separate AS capacity bids? Or should compensation for AS be based solely on an opportunity cost determination?

In addition, market participants have also raised other concerns regarding the optimization program.

Open Issue: Alignment between the OPF objective function and payment structure (i.e., Pay-as-bid v. MCP).

Open Issue: Gaming exposure – relationship between capacity v. energy in the optimization.

Open Issue: Is there alignment between ISO's OPF and NYISO's? (Regulation)

Open issue: Should there be a cap on A/S capacity (See NYISO an PJM)?

When determining real-time LMPs, the the "Base Case" optimization would once again consider the defined network topology (network model, including updated nomograms), the resource (generation and load) attributes, as determined from EMS telemetered data, and the bids submitted by market participants (energy curve, AS capacity).

As discussed above, as part of developing its new EMS program the ISO is developing a state estimator. A state estimator is a essential tool for obtaining accurate real-time information on the status of the system. In the absence of a functioning state estimator, the ISO would basically determine real-time dispatch and prices based primarily on existing and known load distribution factors. That is, instead of determining location specific dispatch and prices based on the detailed information that would otherwise be provided from the state estimator, the ISO would determine such dispatch and process by inputing values from selected known (telemetered) data and load distribution factors.

Open Issue: Should the ISO rely on a state estimator for calculating real-time LMPs or should the ISO rely on available distribution factors?

<u>Equity and Transitional Issues - Congestion Revenue Rights (aka FTRs), Load Aggregation Areas and Existing Transmission Contracts (ETCs)</u>

As outlined in the MD02 proposal, the transition to nodal LMP pricing requires that the ISO redefine and distribute a new form of Firm Transmission Right (FTR), or, as identified in FERC's SMD NOPR, Congestion Revenue Right (CRR). The proposed to develop new direction-specific point-to-point FTRs that are "obligations" (i.e., convey an obligation to schedule and make the holding party liable for congestion costs in the direction opposite their right). Based laregley on equity concerns raised over the transition to LMP and the fact that existing load has traditionally paid the embedded costs of the facilities associated with the FTRs, the ISO proposed to allocate the new FTRs to load based on their historical usage of the grid. The ISO also proposed to auction any residual or leftover FTRs once the allocation was complete. Finally, the ISO proposed to remove a sufficient amount of transmission capacity from the FTR allocation and auction process to ensure that it could continue to honor existing transmission contracts. A number of market participants have raised issues with respect to the details of the ISO's proposal.

> ***Open Issue: How precisely will load be allocated FTRs? How will the ISO determine historical usage?***
>
> ***Open Issue: Before deciding the merits of LMP, market participants must know how many FTRs they will be allocated? (i.e., level of hedge).***
>
> ***Open Issue: How will ETCs be modeled (honored) in the network model and FTR auction?***
>
> ***Open Issue: What is the status and details of the ISO's proposed interim (6-month 2003) FTR auction?***

In addition, and as outlined in the ISO's MD02 proposal, the ISO also proposed to establish certain load aggregation areas wherein load located within these areas could and would pay the weighted average locational price for that area instead of the nodal price for energy at a specific location. The ISO reasoned that this would in part address concern about certain load being exposed to high locational prices. Once again, market participants have raised issues with respect to the ISO's proposal.

> ***Open Issue: Are the ISO's proposed load aggregation areas the appropriate areas?***
>
> ***Open Issue: What are the exact load pricing areas proposed by the ISO? What is the basis for creating those specific load aggregation areas?***
>
> ***Open Issues: How will the load aggregation areas change over time?***
>
> ***Open Issue: Recognizing that transmission constraints give rise to locational price differences, how does the ISO propose to establish an effective transmission planning process in the future?***

Long-term Resource Adequacy

An integral element of the ISO's MD02 proposal is the Available Capacity or ACAP Obligation on load-serving entities (LSEs). The purpose of the obligation is to ensure that load-serving entities procure sufficient resources to satisfy their expected load plus reserves. As proposed by the ISO, the requirement would support reliable operation of the grid by requiring LSEs to identify and provide, in the forward market, the ISO with sufficient resources to satisfy forecast load, thus obviating the need for the ISO to procure a large amount of resources in real-time. In addition, the ISO envisioned that the capacity obligation would translate into and support forward contracting by LSEs and the development of new supply resources in the California market. A number of market participants raised concerns regarding the ISO's proposal and certain market participants proposed alternative proposals.

While most market participants support the need for a long-term resource adequacy requirement or mechanism, there exists little consensus on what such a requirement or mechanism would look like. Through the SMD NOPR, FERC has also proposed a long-term resource adequacy mechanism. In order to move towards consensus, the following issues must be resolved:

Open Issue: What are the objectives of establishing a long-term resource adequacy requirement?(short-term, long-term, or real time)

Open Issue: Should the long-term resource adequacy requirement be phased-In? Should the long-term resource adequacy penalties be phased in? The long-term resource adequacy requirement should recognize "regulatory" constraints.

Open Issue: On whom should the obligations of satisfying the long-term resource adequacy be placed? (Load, Supply, ISO). How should load-serving entity or "LSE" be defined?

Open Issue: What is the appropriate distinction between "capacity" and "energy"?

Open Issue: Who should set the reserve number? How should that number be determined?

Open Issue: Should there be symmetrical obligations on both load and supply?

Open Issue: What is the appropriate role of the various entities involved in satisfying long-term resource adequacy?

Open Issue: What is the appropriate planning horizon?

Open Issue: What kind of resources should be able to satisfy the resource adequacy requirement? (ETCs, Renewables, QFs, State Contracts, Energy-limited Resources, Imports, Demand Response)

Open Issue: Should a capacity obligation be location specific? Should the requirement include a "deliverability" requirement?

Open Issue: What types of market power mitigation mechanisms/strategies be incorporated into a long-term resource adequacy requirement?

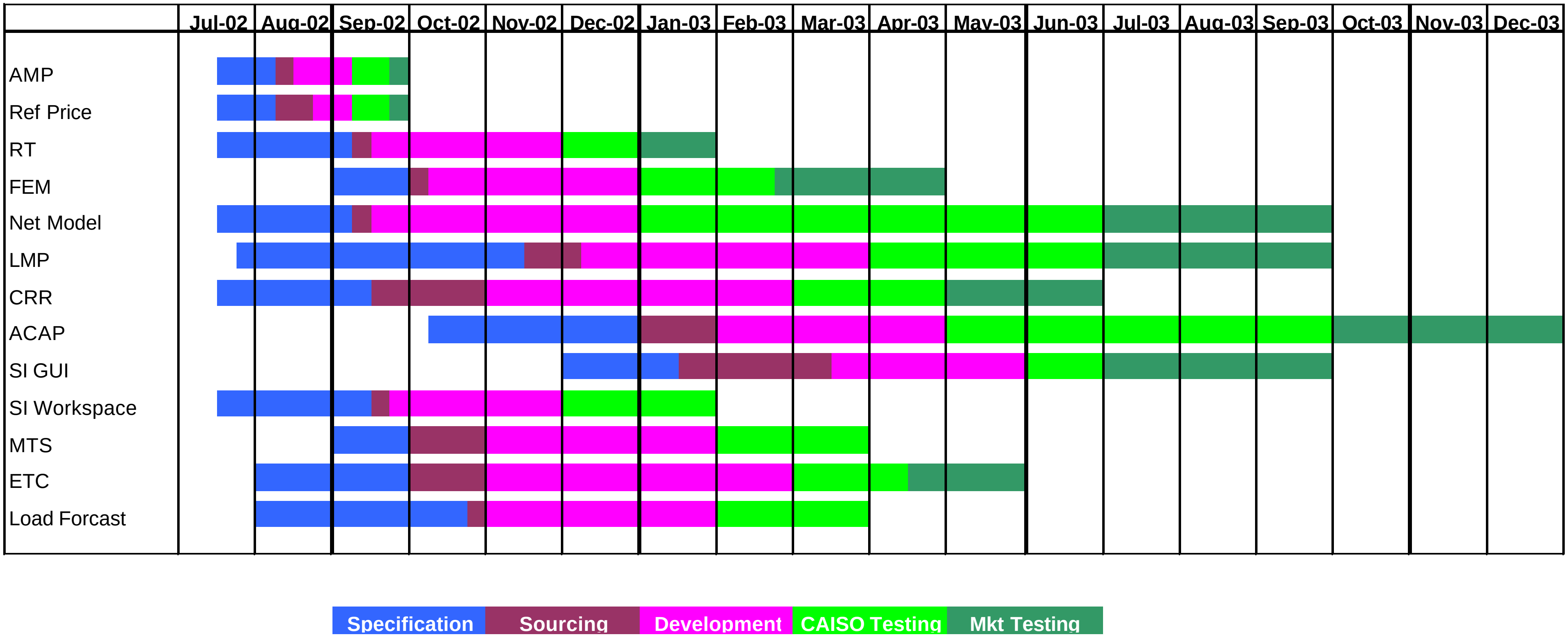
Open Issue: What type of incentive/penalty mechanisms should be incorporated into a long-term resource adequacy requirement or mechanism?

Open Issue: Should a capacity obligation provide for a “pooling” concept? What are the “property rights” to owned capacity?

Open Issue: How should RMR be treated under a long-term resource adequacy requirement?

Open Issue: What is the appropriate division of jurisdictional responsibilities?

Attachment A



Market Design 2002
Straw Proposal
Structure and Guidelines for Stakeholder Working Groups

Introduction

At the FERC-sponsored MD02 workshops in San Francisco on August 13-15, 2002, participants decided that stakeholder groups should be formed expediently to begin working collaboratively to resolve outstanding design issues related to the ISO's MD02 proposal. Such groups should strive to develop design recommendations that address the salient concerns of all segments of the stakeholder community and thus can be broadly supported before FERC. This document offers a Straw Proposal for establishing such a working group process, as a starting point for the conference call scheduled for Tuesday August 20.

This document starts from a few preliminary observations:

- Certain decisions about the MD02 implementation sequence and timetable may take another ten days to two weeks to resolve; i.e., the questions of whether to combine Phase 2 (Integrated Forward Markets) and Phase 3 (LMP, Full Network Model, FTRs) into a single implementation phase, and what the revised implementation timetable will look like. Nevertheless, the working groups should and can begin immediately to work on their own start-up activities while these other decisions are proceeding in parallel. Once the over-arching MD02 implementation approach is decided, the individual groups can adjust their timetables accordingly.

- The process described in this document emphasizes the design stage of MD02, which will probably last two to four months depending on the phasing decisions noted above. Some parties have indicated a need for a lengthier process that goes beyond design into the areas of specification and development. For the sake of getting the process off the ground quickly, this document suggests dealing with first things first, and postponing for a later discussion how to structure stakeholder participation in later stages of MD02.

- It is a practical necessity to start this effort by keeping the number of working groups to a minimum and defining working group subject areas that address the fundamental design and policy issues that must be resolved first to enable the MD02 project to proceed. This means that some topics may not be covered in the initial working group structure, and will need to be addressed by establishing additional groups later in this process. (Some specifics are discussed at the end of this document.)

- In parallel to this process it will probably be necessary for each stakeholder "segment" (for example, suppliers, municipals and governmental entities, investor-owned utilities, large customers, and state agencies) to organize some kind of team of its members to discuss issues, develop and evaluate proposals, and ensure consistency of its positions in the various working groups.

The remainder of this Straw Proposal covers the following topics:

- Organization of the working group process
- The individual working group Charter
- Role of the working group Sponsor
- Proposed initial working group subject areas
- Additional issues and decisions needed.

Organization of the open working group process

This section provides an overview of a proposed organizational structure. Many of the key points are stated briefly, with further elaboration in subsequent sections.

1. The working groups will ultimately be advisory to the ISO's MD02 process and to FERC staff. As such they will seek to develop and present recommendations in their assigned subject areas that reflect, as far as possible, the concerns and interests of all their participants.
2. Decisions and recommendations will be reached at the working group level. Outcomes of the working group efforts will be presented directly to the ISO and to FERC staff both via documentation and in presentations at FERC-sponsored workshops. It does not seem necessary to establish an intermediary or "plenary" stakeholder group to review the working groups proposals, make decisions, endorse or modify recommendations, etc., and it would be costly in terms of time and effort to do so – see the following point.
3. Periodic workshops will occur (timing TBD; perhaps every four to six weeks), including all the working groups and FERC staff, for the purpose of
    - presenting recommendations and status reports of each working group,
    - coordinating among the separate working groups (ensuring that the separate pieces fit together), and
    - identifying and addressing over-arching issues or problems on which broader group input or FERC input is needed.
4. Each working group will be open to all stakeholders who want to participate. Also, the positions of parties at the working group meetings will not be binding in any respect, including subsequent FERC proceedings. At the same time, it is essential to keep the groups to a practical size for getting their jobs done, and to avoid getting bogged down by having to educate participants who are not up to speed (see discussion of participant responsibilities, under Charter).

5. Each working group will have a Sponsor who will provide organizational and facilitation service to the working group (details below). It is suggested that each major stakeholder segment offer to sponsor one of the initial working groups, and each segment select from among their own ranks the specific entities and individuals who will perform the needed functions.
   - NOTE: It can be extremely difficult if not impossible for a person who represents a particular point of view also to facilitate meetings in a neutral manner that safeguards the group process. Participants in this working group process should carefully consider whether to engage the services of professional facilitators, or whether they have such skills within their own staff and can provide individuals to perform meeting facilitation without engaging in advocacy.
6. Each working group will begin its effort by establishing a Charter (details below) that serves to guide its activities.
7. The working group will try to reach unanimity (i.e., full agreement) on recommendations as far as possible. Where this is not possible, it will try to identify majority opinions and will capture the concerns or objections to such majority opinions.
8. The ISO will provide, via its web site, the communications capability needed to support this effort.

The individual working group Charter

Each working group should begin by establishing some foundational elements for its effort, as described below, which constitute the working group's "Charter." Once the Charter is drafted, adopted and documented by the working group, it should be a standard reference for all activities of the group. The Charter need not be set in stone, however, and if necessary, the group can amend the elements. The following elements of the Charter should probably be developed in the order stated:

- A statement of purpose (mission statement) that describes what the group intends to accomplish, the product the group intends to produce, and the over-arching time frame for completing its mission.
- A statement of scope that identifies the topics included in the group's effort and sets some boundaries.
- A set of guiding principles that capture the key concerns or needs of each of the participants. For this process to work, it is important that participants be candid about their needs and their criteria for supporting or opposing a proposal – hidden agendas are not compatible with a good faith collaborative process and will inevitably undermine it. Similarly, it is important that participants acknowledge and be willing to accommodate the needs expressed by others in the group – if any of these fundamental needs are mutually incompatible or unacceptable to any participants, it must be identified up front as it will continually impede the group's

progress. The principles identified at this stage become the criteria for evaluating proposals and making decisions as the group's work progresses.

- A set of guidelines for the day-to-day meeting process, such as:
  - Each working group participant will stay up to speed with the activities of the working group and with the views and opinions of other members of his/her stakeholder segment. (The group may want to spend a limited amount of time at the start of each meeting to review previous progress and bring everybody up to speed, e.g., 10 minutes);
  - Each participant will deliver, on time and as complete as possible, any assignments to be performed outside the group meeting process;
  - Each participant will listen carefully to what others are saying and will allow others to fully express their ideas;
  - Each participant will help to facilitate meetings, i.e., support the Chair in keeping the meeting focused on intended outcomes, maintaining the meeting guidelines, helping to clarify miscommunication when it occurs, referring to the Charter to help move through stuck points, etc.; and
  - Each participant will assume responsibility to communicate to affected and interested parties within their own company.
- Decision-making criteria and guidelines that will guide the group's efforts in resolving issues;
- A date certain when decisions are needed in order to implement MD02 in a timely manner.

Role of the working group Sponsor

The Sponsor has an organizational and facilitation role, which should include:

- Chairing meetings, providing leadership to keep the meeting focused and on track;
- Providing a "neutral" environment in which all points of view are heard and given due consideration (as noted above, this may require engaging the services of professional facilitators);
- Preparing and posting agendas for meetings in advance; this should include a statement of the desired outcomes of each meeting;
- Capturing and posting summaries of meetings, identifying
  - The topics and issues discussed
  - Where resolution was reach on each issue
  - Where resolution got stuck and the identified options for resolution

  - Issues identified for discussion at next meeting
  - Any activities or deliverables to be completed outside the working group meeting, the persons responsible and the due date.
- Adhering to the decision-making process and schedule.

Proposed initial working group subject areas

This Straw Proposal suggests starting with four working groups, and forming additional ones later as needed. The four subject areas are defined to try to capture all the issues that must be addressed on the most expedient time frame. Note that this Straw Proposal includes market monitoring and market power mitigation in each of the working group areas to be addressed within those areas, rather than having a separate working group on these items.

Working Group 1. Long Term Resource Adequacy – including all the issues encompassed by the ACAP, AFEC, Reliant and SMD resource adequacy proposals, addressing both global (system-wide) and local supply needs (e.g., RMR).

Working Group 2. Integrated Forward Markets – including: day-ahead and hour-ahead markets, market separation, integrating congestion management with energy trading and ancillary services procurement, three-part bids and simultaneous unit commitment, reliability or residual unit commitment, virtual bidding, treatment of physical bilateral contracts, market monitoring and market power mitigation.

Working Group 3. LMP & FTRs – including: full network model, nodal pricing, load aggregation, the FTR or CRR design, allocation of FTRs, treatment of converted and non-converted ETCs, market monitoring and market power mitigation.

NOTE: If we decide to implement Phases 2 and 3 in a single phase, then working groups 2 and 3 are on roughly the same time frame. Alternatively, if we retain the separate implementation phases and implement integrated forward markets in spring 2003 as ISO originally proposed, then WG 2 will be on a much shorter time frame than WG 3, and the specific content of WG 4 (below) will be somewhat different.

Working Group 4. Interim Provisions – Given the likelihood that "interim" arrangements may need to be in place until late 2003, what interim design elements are needed for a functional system that minimizes the risk of near-term provisions undermining long-term objectives. This could include: Phase 1 implementation issues (e.g., real-time economic dispatch), moving up the HA market time frame, near-term resource adequacy (e.g., must offer and interim RUC), system-wide and local market power mitigation, etc.

<u>Additional Issues</u>

There are some additional topics that are not included in the above working group structure. For reasons of simplicity, expediency and efficient use of resources it is suggested that the issues not included above be placed on a secondary, but parallel, track and addressed via formation of another working group later in this process. If certain issues absolutely must be addressed right at the outset then perhaps they can find a home in one of the above groups, rather than requiring a fifth working group. The “address later or on a separate track” list might include:

- Settlement procedures and time line
- Transmission planning
- Metering and meter data management issues
- Training of market participants on the new market rules and systems
- Very technical issues (e.g., AC versus DC power flow; representation of the external network for loop flows; modeling of nomogram constraints)
-

Additional issues and decisions needed

- Need for professional facilitation services (may be left up to individual working groups to decide).
- Anticipated or desired role of FERC staff (both within the individual working groups and at the higher review level).
- How to provide and pay for practical needs (e.g., meeting facilities).

The Joint Application Development (“JAD”) Process

The ISO proposes to initiate a Joint Application Development or “JAD” process to facilitate stakeholder involvement in the development of detailed design specifications. The JAD process for each element or set of elements will begin as soon as the major unresolved policy-level design issues are resolved through the working group process outlined above. For example, now that most, if not all, of the design issues regarding AMP, real-time economic dispatch and penalties on uninstructed deviations have been resolved, the ISO intends to shortly schedule JAD sessions for these topics.

Attachment C

MD02 Consolidated Open Issues List	
#	**Issue (Categorized and Listed by Phase)**
Phase I	
	AMP
1	ISO rehearing issue. The ISO has filed for rehearing of the new FERC-established AMP thresholds. The ISO believes the AMP thresholds proposed by the ISO are appropriate.
2	ISO rehearing issue. The ISO has filed for rehearing of the new FERC-established AMP price screen test. To the extent that the Commission believes a price screen is necessary, the ISO believes a lower price screen is appropriate.
3	Next Steps if there are no responses to AMP Reference Price RFP or if bids are exorbitantly priced.
	Local Market Power Mitigation
4	ISO rehearing issue. The ISO has filed for rehearing of FERC's order on the Local Market Power Mitigation. The ISO does not believe that FERC's directive adequately mitigates the exercise of local market power.
5	ISO clarification issue. The ISO has filed for clarification from FERC that FERC did not contemplate the ISO "decrementing" or "dec"ing Reliability Must-Run (RMR) Generation for purposes of managing Intra-Zonal Congestion (AZCM). The ISO does not have the ability to "Dec" RMR units for AZCM.
	12-Month MCI
6	ISO rehearing issue. The ISO has filed for rehearing that the 12-Month MCI reporting requirement should be a monthly, rather than weekly, reporting requirement.
	Real-time Economic Dispatch and Penalties on Uninstructed Deviations
7	How to calculate, validate and incorporate multiple ramp rate information for each generating unit?
	Interim Residual Unit Commitment
8	ISO rehearing issue. The ISO has filed for rehearing on this issue arguing that FERC should not have rejected the ISO's proposed Interim RUC process.
9	ISO clarification Issue. The ISO has filed for clarification that the July 17 Order authorized the ISO to use its existing TCUC software, which includes a security-constrained, least-cost algorithm, for committing resources through the existing Must-Offer waiver process.
Phase II	
	Integrated Forward Market
10	ISO rehearing issue. The ISO has filed for rehearing of FERC's directive to implement the new Phase II integrated zonal market by January 1, 2003. The ISO does not believe that the expedited schedule established by FERC is feasible and will not allow for proper system integration and testing.
11	Should the ISO's MD02 proposal include a hour-ahead energy market?

12	Does the ISO need to facilitate forward financial markets?
13	Should the ISO permit the submission of financial or "virtual" bids in its day-ahead and hour-ahead markets? (i.e., let such transactions take place outside – bilateral/third-party facilitated - of the ISO's markets, which, certain participants believe, should be primarily physical?)
14	Should the ISO require that all financial or "virtual" bids be clearly identified or "flagged"?
15	Who would see a "Flag"?
16	What is the appropriate staging in the ISO market redesign for a financial market?
17	ISO Homework – Implications on Design + Implementation from incorporating requirement to distinguish between financial and physical bids.
18	Cost / Complexity / Benefit of an ISO – facilitated financial market
19	Scheduling bilateral transactions. Need clarity on how this works?
20	How can bilateral schedules be protected? (Will the optimization include a "flag"?)
Residual Unit Commitment	
21	Through what mechanism/tool should the ISO commit resources prior to implementation of a long-term resource adequacy mechanism and commitment process?
22	Should start-up and minimum load be "cost-based"? Minimum load "energy" should get paid MCP? Price depression
23	Start-up and no-load bids/costs
24	How does RUC relate to resource adequacy?
25	Concerned about capacity payment under "near-term" RUC proposal?
26	Should the ISO instead use Replacement Reserves rather than relying on RUC?
27	How does RUC work in conjunction with Price Mitigation? Particularly with limited run time resources.
28	How does curtailable-load resource fit into RUC? Resource Adequacy? Energy Bids ("Inc" can't go up) Ramp Rates / Min. Up/Down Accommodations - Physical Operation Constraints
29	Interim process may be more important than long-term (i.e. don't want to create mechanism that makes matters worse)
30	Relationship between RUC, capacity adequacy and physical withholding? How to prevent physical withholding? (short-term, long-term)?
31	Is there a symmetrical performance obligation for other loads and resources?
Optimization (OPF) Parameters	
32	Should capacity bids be included?
33	Alignment between OPF objective function and payment structure: Pay-as-bid v. MCP.
34	Gaming exposure – relationship between capacity v. energy
35	Is there alignment between ISO's OPF and NYISO's? (Regulation)
36	Should there be a cap on A/S capacity (See NYISO an PJM)?
37	Should the optimization include schedules that are known to be financial only?
38	Should the optimization objective function include AS capacity bids? Or should compensation for AS be based solely on an opportunity cost

	determination?
39	Should the start-up and minimum load components be cost based or bid-based? If cost-based, how often should market participants be able to change these values?
General	
40	How will settlements work?
41	How can losses be self-provided?
42	How can SCs "protect" energy-limited and load-based resources?
43	Sufficient Time to review "specs" to ensure programs do not facilitate/subject to manipulation
44	Testing – Sufficient time
45	Value added - $ should be worth it!
46	Proper alignment /declination, roles responsibilities, accountability
47	What is the status of the ISO's proposed interim (Spring 2003 to Fall 2003) FTR auction?
Phase III	
Network Model & State Estimator	
48	Should the ISO develop and utilize a AC or DC OPF for calculating LMPs?
49	Should the ISO rely on a state estimator for calculating real-time LMPs or should the ISO rely on available distribution factors?
50	Once we have the full network model, will the ISO be able to more accurately assess and charge for UFE?
Locational Marginal Pricing and "Equity Issues"	
51	How / whether should RMR be phased out?
52	Need detailed studies (empirical) on impact of LMP.
53	Want to know study details/parameters.
54	Equity issues – Transition to LMP: CRRs; Load Aggregation - Need details
55	How do we get to an effective TX planning process?
56	How will ETC s be honored and modeled in network model and FTR auction?
Long-Term Resource Adequacy	
57	Should the long-term resource adequacy requirement be phased-In? Should the long-term resource adequacy penalties be phased in? The long-term resource adequacy requirement should recognize "regulatory" constraints.
58	What are the objectives of establishing a long-term resource adequacy requirement?
59	On whom should the obligations of satisfying the long-term resource adequacy be placed? (Load, Supply, ISO)
60	Should there be symmetrical obligations on both load and supply?
61	What is the appropriate role of the various entities involved in satisfying long-term resource adequacy?
62	What is the appropriate planning horizon?
63	What kind of resources should be able to satisfy the resource adequacy requirement?
64	What types of market power mitigation mechanisms/strategies be incorporated into a long-term resource adequacy requirement?

65	What type of incentive/penalty mechanisms should be incorporated into a long-term resource adequacy requirement or mechanism?
66	What is the appropriate division of jurisdictional responsibilities?

CALIFORNIA ISO

California Independent
System Operator

August 27, 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 Reply Comments 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 27th day of August, 2002.

Anthony J. Ivancovich