Executive Summary

The CAISO's Market Design 2002 Project

The CAISO initiated the Market Design 2002 (MD02) project to (1) take a comprehensive view of the changes needed in the structure of California's electricity markets, particularly markets operated by the CAISO, and (2) develop a program of proposed market design changes that will address current problems in a systematic fashion and create a framework for a sustainable, workably competitive electric industry that benefits all California consumers and is compatible with the rest of the western region. The primary design effort on this project is assigned to an inter-departmental team of CAISO staff referred to as the MD02 team.

The first deliverable of the MD02 project is a Comprehensive Design Proposal that identifies the problems to be addressed and describes the entire program of market changes proposed to address those problems. The CAISO expects to complete the Comprehensive Design Proposal in February, after conducting a series of focus groups during the week of January 14 to obtain the input of market participants and other industry stakeholders. The present document is a preliminary draft of the Comprehensive Design Proposal, which the MD02 team has prepared for discussion in the upcoming focus groups. This preliminary draft represents the current design direction the MD02 team is tending towards, and also identifies a number of questions and issues which the MD02 team has not yet addressed and is identifying for discussion in the focus groups. This draft should therefore be viewed as a work in progress by CAISO staff rather than a formal market design proposal of the CAISO.

Following the completion of the Comprehensive Design Proposal, the CAISO expects to file its proposed market changes for approval by the Federal Energy Regulatory Commission (FERC) in two phases. Phase 1 will contain the changes to the CAISO Tariff needed to implement those market design elements that are essential to be in place by September 30, 2002, when the existing FERC market mitigation measures are set to expire. Phase 2 will contain the changes to the CAISO Tariff needed to implement the remaining elements of the Comprehensive Design, which the CAISO expects to implement during the latter part of 2002 and the early part of 2003.

The Elements of this Preliminary Draft Comprehensive Design Proposal

The elements that comprise this preliminary draft proposal were crafted from the MD02 team's synthesis of a number of materials, including: (1) staff analysis of the root causes of California's power crisis, (2) nearly four years of experience operating the CAISO markets and the grid, (3) the design and performance of other ISOs, and the numerous rulings FERC has made on their filings, (4) the design elements of the January 2001 Congestion Management Reform proposal
developed through an inter-departmental CAISO staff effort, and (5) the design elements of the April 2001 Market Stabilization Plan developed by the CAISO to ensure market and operating stability over summer 2001. In addition this draft has benefited from the input of stakeholders in numerous public meetings held at the CAISO over the past two years, particularly in relation to items (4) and (5) above.

As a result of this synthesis, the preliminary draft proposal presented in this document retains some of the successful elements of the CAISO’s existing design, adopts design elements that have proven successful in other ISOs, and in some areas offers novel suggestions to address as yet unsolved problems. Some of the principles that have been guiding the MD02 team and shaping this draft proposal, and will shape the ultimate Comprehensive Design Proposal, are to:

- improve upon the CAISO’s performance of its core functions, particularly the provision of non-discriminatory transmission service and reliable operation of the grid;
- identify and address the root causes of problems; in particular, provide incentives and means for buyers to limit their exposure to volatile spot prices and for suppliers to fully offer all available capacity to the market;
- ensure that forward market price signals, incentives, and transmission allocation rules are consistent with and support real-time operating needs;
- design for flexibility and open architecture so the market design and the implementing systems are adaptable to changes, such as key FERC rulings expected over the coming year and the development of Regional Transmission Organizations in the west;
- strive for simplicity and transparency, and make the CAISO a more attractive place for all participants to do business;
- provide adequate, timely, and transparent information, tools and incentives for market participants to self-manage their business activities and risks in the forward markets;
- accommodate the needs of diverse CAISO participants, including municipal and other vertically-integrated utilities that use the CAISO grid and markets; and
- strive for the creation of a seamless western market by addressing seams issues.

The specific design elements discussed in this preliminary draft proposal are:

1. Available Capacity (ACAP) Obligation on Load Serving Entities. The main purpose of the ACAP obligation is to ensure that adequate capacity is available on a daily basis to meet system load and reserve requirements. Under the original California design there was no entity with explicit responsibility to ensure adequate capacity. The ACAP obligation would apply to all entities that serve end-use electricity consumers, in proportion to their peak monthly demand. It is doubtful that this provision can be fully effective by September 2002, however, so the CAISO may perform a supplementary ACAP procurement during a two-year transition period.

2. Day-ahead Congestion Management. Would use a fully accurate model of the CAISO grid for the purpose of adjusting generation and load schedules to mitigate transmission overloads and ensure local reliability, instead of today’s simplified three-zone model. With this change the CAISO will be unable to preserve the “Market Separation Rule,” and some energy trading between participants will occur in the process of managing congestion. The proposed design will still provide ways to establish firm physical schedules, and will allow commercial energy trades at a few key “trading hubs.”

3. Firm Transmission Rights (FTRs). These are financial instruments that allow participants to hedge the risk of congestion charges. With the changes to congestion management as
proposed above, the CAISO will also need to change the design of its FTRs to specify an explicit generator location and load location, rather than between any two arbitrary locations on either side of a designated transmission pathway.

4. Forward Spot Energy Market. With the demise of the Power Exchange the California energy market lost the primary vehicle for day-ahead energy trades to shape supplies to meet the next-day’s expected demand. Without the CAISO creating a new spot market, the proposed congestion management approach will result in energy trades between participants anyway. It may still be desirable, however, to create a new market similar to the Power Exchange.

5. Residual Day Ahead Unit Commitment. Unit commitment refers to the decision to start up a generating resource that has a long start-up time, so that it will be running at the time it is expected to be needed to meet demand. The current design leaves commitment decisions entirely to participants and gives the CAISO no ability to commit additional units in advance even when the forecast indicates they will be needed. Under the proposal, the CAISO would evaluate whether day-ahead schedules include enough on-line resources to meet the next day’s demand forecast, and if not, the CAISO would be able to commit additional units. The ACAP obligation mentioned above would ensure that units respond to CAISO commitment instructions.

6. Real-time Economic Dispatch Using Full Network Model. Every 10 minutes during each operating hour the CAISO would run a “security-constrained economic dispatch” program to determine which resources to dispatch at what operating levels to meet real time needs. This approach would meet the CAISO’s operating needs most accurately and efficiently by fully taking into account all transmission constraints, local reliability needs, and generator operating constraints, as well as system imbalance energy needs. This approach would produce nodal real-time energy prices, which would be paid to supply resources but could be aggregated to larger geographic areas for settling imbalance energy purchases by load serving entities.

7. Real-time Bid Mitigation for Local Reliability Needs. Under the current rules a supplier at a constrained location on the grid can often earn a premium price by virtue of being the only one who can relieve the local constraint. Suppliers who are aware of their strategic locations are said to have locational market power, and often exploit this by bidding extremely high to increase their output, or extremely high in the negative direction to decrease their output, knowing that the CAISO must dispatch them. To limit exploitation of locational market power the CAISO would propose bid mitigation measures similar to those approved by FERC for other ISOs.

8. Damage Control Price Cap on CAISO Markets. Without the price mitigation provided by the FERC market mitigation orders, the spot markets will be vulnerable to occasional extreme peak prices. All other ISOs have some level of damage-control price cap to limit the adverse cost impacts of an unusually severe price spike. The MD02 team proposes that such a cap be established for the CAISO markets, but has not yet developed a recommendation on the level of this cap.

In addition to the above elements the MD02 team is considering some changes to the CAISO’s Ancillary Services markets and to the structure and timing of the Hour Ahead market. Proposals in these areas were not ready for inclusion in this preliminary draft.
1. Introduction

This document is intended as a discussion piece for the market participant focus groups on market design to be conducted by the CAISO on January 14-17, 2002. As such it provides an overview of the background, objectives, market design options and preliminary proposals of the CAISO’s Market Design 2002 (MD02) project. The CAISO initiated the MD02 project to (1) take a comprehensive view of the changes needed in the structure of California’s electricity markets, particularly the markets operated by the CAISO, and (2) develop a program of proposed market design changes that will address current problems in a systematic fashion and create a framework for a sustainable, workably competitive electric industry that benefits all California consumers and is compatible with the rest of the western region.

Background

Causes of the California electricity crisis. Since the beginning of the electricity crisis in Summer 2000, the CAISO has been assessing the structural features and design elements of the restructured California markets that contributed to the crisis. In an early report on the subject the CAISO identified the following root causes:

1. Tight supply conditions in California and throughout the western region;
2. Under-scheduling in the forward markets, which increases the volume of the CAISO real-time market far beyond its original design and raises the cost and difficulty of ensuring reliable operation of the grid;
3. Lack of demand responsiveness to hourly prices, due to (a) limited technical capability for real-time price-responsiveness; (b) insufficient forward contracting for energy; and (c) ambiguous accountability for reasonably-priced power acquisition for retail consumers;
4. Exercise of market power, both at the system-wide level and in connection with local reliability needs;
5. Inadequate transmission capacity to support competitive markets throughout the CAISO system; and
6. Needed enhancements to market rules to improve market efficiency and to ensure that forward schedules are feasible.

Clearly not all of the above problems are resolvable through CAISO market design changes. In particular, tight supply in the western region, limited demand responsiveness, and inadequate transmission infrastructure are areas where CAISO market design changes will contribute only partially to the solution.

The need to reform the CAISO’s congestion management. Even before the crisis began in Summer 2002, FERC’s January 2000 rejection of locational market power mitigation provisions of the CAISO’s Amendment #23 had prompted the CAISO to initiate a project to correct fundamental flaws in its congestion management procedures. This Congestion Management Reform (CMR) project held extensive stakeholder meetings in the process of assessing design options, and culminated in the CMR proposal of January 2001 which is available on the CAISO web site. At that time, however, the CAISO was unable to move forward to seek FERC approval or to implement this proposal due to the ongoing power crisis.

The CAISO’s Market Stabilization Plan. During the winter and spring of 2001, anticipating potential shortages in the coming summer the CAISO developed a Market Stabilization Plan (MSP) to ensure adequate supply and to mitigate market power. As in the case of CMR, the
CAISO held stakeholder meetings to discuss the options being considered in the MSP. During the same period FERC was developing its preferred market mitigation plan for California and the western region, and in this context ordered the CAISO to file the MSP on April 6. The CAISO’s MSP filing is also available on the CAISO web site.

**FERC’s Market Mitigation Orders.** FERC issued its initial market mitigation order on April 26, 2001, followed by a second order on June 19 that revised, clarified and expanded upon the April 26 order. Then on December 19 FERC issued extensive orders responding to the CAISO’s compliance with the mitigation orders and addressing the clarification and rehearing filings numerous parties had made. These orders collectively comprise the market mitigation framework that exists in California today and is due to expire on September 30, 2002. This framework provides a number of important provisions which have helped ensure stability and reasonable prices in the CAISO’s markets. The major provisions include:

- The requirement for all in-state non-hydro generating units to bid all available capacity into the CAISO’s real-time market in all hours (the “Must Offer Obligation”);
- Price mitigation in the real-time market in all hours; in particular, a cap on the real-time market clearing price (MCP) during non-emergency hours that is set based on the highest-cost in-state generator that ran during the most recent Stage 1 System Emergency (the “Non-Emergency Clearing Price Limit” or NECPL), with cost justification required for bids exceeding the cap;
- The requirement that marketers (i.e., suppliers whose supply can not be tied to a specific generating unit) bidding into the real-time market be paid at the MCP but not be able to set the MCP (the “Price Taker” requirement).

The CAISO believes that the provisions of these market mitigation orders have helped to ensure adequate supply in real time at reasonable prices. We are concerned, however, for reasons discussed further below, that not all features of the market design being considered in this document can be fully implemented by September 30 when the mitigation orders expire. The MD02 effort has therefore placed great emphasis on identifying the essential provisions that will be needed at that time to ensure continued operational and market stability.
2. The Market Design 2002 Project

The CAISO initiated the Market Design 2002 (MD02) project in October 2001, and assigned the primary design effort to an inter-departmental team of CAISO staff referred to in this document as the MD02 team. The present draft represents the current design direction the MD02 team is tending towards. As such the contents herein should be viewed as a work in progress by CAISO staff rather than formal market design proposal of the CAISO. The remainder of this section frames the MD02 design effort by providing the mission statement, scope, deliverables and timing, guiding principles, and design objectives.

Mission Statement

The mission of the MD02 Project is to develop, obtain Board approval for, and file at FERC a program of CAISO market design changes needed to ensure the CAISO’s effective and sustainable performance of its core functions, position the CAISO to better serve the needs of all of its customers, and support efficient performance of the electricity markets for the benefit of all California consumers.

Scope

To accomplish the stated mission, the program of market design changes developed by the MD02 project will:

1. address the underlying deficiencies that led to the 2000-2001 electricity crisis, to the extent these deficiencies can be mitigated by CAISO market design changes;
2. correct the major design flaws in the CAISO markets, some of which were identified well before the crisis began;
3. provide a menu of services that better meet the demands of the CAISO’s diverse group of customers and market participants (including municipal and other vertically integrated utilities that utilize CAISO-controlled facilities and CAISO markets);
4. be feasible to implement in stages between Spring 2002 and Summer 2003;
5. provide necessary features to ensure stable market performance and system operation when the FERC June 19 Order expires on September 30, 2002;
6. be consistent with and build upon the real-time market changes associated with the “Real-time Market Pricing” proposal (i.e., the permanent Target Price solution) currently being prepared for filing;
7. fulfill the CAISO’s commitment to FERC to file a permanent solution to intra-zonal congestion problems to replace the interim solution recently approved by the Board and currently being prepared for filing;
8. be compatible with the designs being developed by RTOs in the western region and address other seams issues as necessary to ensure, to the greatest extent possible, a seamless energy market in the West.

 Proposed Deliverables and Timing of the MD02 Project

There are a few key considerations and constraints that influence the content and timing of the MD02 project’s major deliverables. These factors are:
FERC’s December 19, 2001 Order on Clarification and Rehearing directs the CAISO “to file by May 1, 2002 its revised congestion management proposal and a plan for implementation of a day-ahead market.”

FERC’s June 19, 2001 Market Mitigation Order expires on September 30, 2002. By that time the CAISO must have adequate market changes in place to ensure stable market performance and reliable system operation.

The CAISO Board recently approved a FERC filing to seek approval of an interim method to address intra-zonal congestion, consisting of forward schedule curtailment authority and real-time price mitigation for local reliability needs. In this filing, the CAISO will commit to delivery of a long-term solution to intra-zonal congestion in the context of a major redesign of congestion management, which would also address in part the required May 1, 2002 FERC filing and is clearly within the scope of MD02.

Significant changes to the real-time market are already underway via the Real-time Market Pricing proposal (i.e., the permanent “Target Price” resolution) recently approved by the CAISO Board and soon to be filed at FERC. The proposal is to implement an economic dispatch algorithm to continuously clear overlapping real-time energy bids, subject to transmission and generator ramping constraints. As a result there will be a single price in each 10-minute interval and a new set of incentives for compliance with dispatch instructions. This proposal will also provide some of the tools needed for further enhancements to the real time market, mainly as a result of the installation of economic dispatch software. These changes are all fully consistent with current MD02 thinking regarding the real-time market.

To accomplish its mission the MD02 project is structured to produce three deliverables.

1. The first deliverable will be a “Comprehensive Design Proposal” that identifies the full set of problems to be addressed and describes the entire program of proposed market changes necessary to address those problems. The word “comprehensive” refers to the scope of the proposal, not to the design details, hence would not include draft tariff language. CAISO management expects to present this proposal to the Board at the February 7, 2002 meeting.

2. The second deliverable will be a Phase 1 FERC filing that presents to FERC the comprehensive design proposal, but provides implementation details and tariff language only for the changes needed to be in place by the September 30 expiration of the current mitigation provisions. The reason for making the Phase 1 filing on a fairly rapid timetable is to ensure that the critical features can indeed be implemented by September 30.

3. The third deliverable will be a Phase 2 FERC filing that addresses the remainder of the proposed design changes developed by the MD02 project, and will be filed by May 1 in compliance with FERC’s December 19 Order.

The present document should be viewed as a working draft of first deliverable of the MD02 project, the Comprehensive Design Proposal.
Proposed Project Timetable

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<tr>
<td>Tue 1/8</td>
<td>Release Comprehensive Design Draft for stakeholder meetings</td>
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<tr>
<td>Week of 1/14</td>
<td>Stakeholder Focus Groups to discuss Comprehensive Design Draft</td>
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<td>Wed 1/23</td>
<td>Stakeholder written comments due to CAISO</td>
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<td>Jan 2002</td>
<td>FERC 205 Filing on Real-time Market Pricing and Intra-zonal Congestion</td>
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<tr>
<td>Week of 1/28</td>
<td>Finalize Board documents re Comprehensive Design Proposal</td>
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<tr>
<td>Thu 2/7</td>
<td>Board meeting – Comprehensive Design Proposal (1st MD02 deliverable)</td>
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<tr>
<td>Thu 3/14</td>
<td>Board meeting</td>
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<td>Week of 3/18</td>
<td>Submit Phase 1 FERC filing (2nd MD02 deliverable)</td>
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<td>Thu 4/25</td>
<td>Board meeting</td>
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<td>Wed 5/1</td>
<td>Submit Phase 2 FERC filing (3rd MD02 deliverable)</td>
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<td>Mid May</td>
<td>FERC ruling on Phase 1 filing, initiate implementation</td>
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<td>Mon 9/30</td>
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Guiding Principles

The initial effort of the MD02 team produced the following principles to guide the development of specific design proposals.

1. Improve upon the CAISO’s performance of its core functions (non-discriminatory transmission service, reliable operation, congestion management, ancillary services, real-time balancing, transparency, timely market information, etc.).

2. Draw upon viable proposals and principles that have been developed or identified through previous CAISO and stakeholder efforts, and upon the CAISO’s experience accumulated over nearly four years of operating its markets and the grid. For example, the January 2001 CMR Proposal and the April 2001 Market Stabilization Plan will both be revisited for the design effort, but will not limit the consideration of other options.

3. Develop a clear understanding of the root causes of problems, and solve problems at that level.

4. Design from ideal viewpoint at first – what is the best design to achieve the objectives – then consider impact of system constraints and other factors that must be accommodated. One implication of this principle is that there are no “pillars” from today’s markets that we are accepting as compulsory design features.

5. Design for flexibility so that the market design and the underlying systems are adaptable and can be easily changed to reflect changed circumstances (e.g., changes resulting from FERC NOPR on RTO market design, changes necessary as a result of evolving western RTO development, as well as principles of open architecture).
(6) Strive for the creation for seamless western market by considering and addressing seams issues.

(7) Appropriately prioritize and stage FERC filings and implementation efforts to ensure that the necessary market design features are in place upon expiration of the FERC-established price mitigation measures.

(8) Strive for simplicity and transparency.

(9) (From January 2001 CMR Proposal) Recognizing that reliable real-time operation of the grid is fundamental to the CAISO’s core function of providing transmission service to support a competitive electricity market, the CAISO’s proposed market design changes must be consistent with and must support real-time operating needs (“the consistency principle”).

**Design Objectives**

The MD02 team identified the following design objectives as a way to translate the mission statement, scope and guiding principles above into more focused, specific CAISO market design issues that need to be addressed in a comprehensive market design proposal.

**Overall**

1. Enhance the CAISO markets to be a more attractive place for all participants to do business.

2. Provide adequate, timely, and transparent information, tools and incentives for market participants to self-manage their business activities and risks in the forward markets (i.e., offer a “toolbox” of services).

3. Accommodate, to the greatest extent possible, the special circumstances and needs of municipals and other vertically integrated utilities that use CAISO systems or markets.

4. Improve operational control of the CAISO-controlled grid.

**Real Time Market**

5. Minimize volume so that real time is a balancing market only. (NOTE: This may be less of a concern than it is today if the CAISO implements a Capacity Obligation and Day-ahead Unit Commitment as discussed below.)

6. Attract adequate supply bids for competitive real-time prices (including increased participation of imports and demand response).

7. Ensure reliable, predictable and adequate performance by generating resources (i.e., maximize incentives to comply with dispatch instructions so that real-time market provides effective load following, with minimal need to rely on Regulation to do load following).

8. Provide price transparency.

9. Provide dispatch transparency – procedures are clear to market participants, are followed consistently by CAISO, and are consistent with price signals (see #8).

10. Ensure CAISO dispatch instructions are responsive to all system and resource constraints, i.e., realistic.

11. Mitigate locational market power.

12. Provide operational simplicity, to minimize burden on real-time operations.

13. Improve ability to maintain Operating Reserves (O/R) within the hour.
14. Ensure inter-control area compatibility.

**Forward Markets (Day Ahead, Hour Ahead)**

15. Ensure adequate capacity is available to meet RT needs.

16. Ensure final schedules are feasible (i.e., satisfy inter-zonal, intra-zonal and ramping constraints).

17. Ensure final schedules are “operable” – scheduled quantities and locations reflect expected reality, i.e., final schedules should be “close” to their real-time profile and adequate supply should be available with proper locational dispersion to meet CAISO’s forecast load. (This may be less of a concern with a Capacity Obligation and Forward Unit Commitment.)

18. Maximize availability and efficient use of transmission capacity.

19. Mitigate both system-wide and locational market power.

20. Satisfy local reliability needs efficiently.
3. Details of Major Design Elements

This section is structured in two parts. Part 1 provides a detailed overview of all elements of the proposed Comprehensive Market Design. Part 2 focuses specifically on elements needed to be in place by September 30, 2002, when the FERC mitigation measure expire.

Part 1. Elements of the proposed Comprehensive Market Design

The proposed Comprehensive Market Design is comprised of the following elements, each of which is discussed below:

1. Available Capacity Obligation on Load Serving Entities
2. Forward Congestion Management
3. Firm Transmission Rights
4. Forward Spot Energy Market
5. Residual Day Ahead Unit Commitment
6. Changes to Ancillary Services Markets
7. Changes to Structure and Timing of Hour Ahead Market
8. Real-time Economic Dispatch Using Full Network Model
9. Real-time Bid Mitigation for Local Reliability Needs
10. Damage Control Price Cap on CAISO Markets.

Available Capacity (ACAP) Obligation on Load Serving Entities

The main purpose of the ACAP obligation is to ensure that adequate capacity is committed on a daily basis to meet system load and reserve requirements and is available to respond to CAISO dispatch instructions to meet system imbalances and local reliability needs. Under the original design of the California restructuring there was no entity with explicit responsibility to ensure adequate capacity. As a result the spot markets of the Power Exchange and the CAISO were vulnerable to market power exercise, and the CAISO frequently faced supply shortages right up to the operating hour. To remedy this problem the proposed ACAP obligation would apply to all Load Serving Entities1 (LSEs), thus placing the responsibility on them to procure adequate capacity to meet their expected peak monthly loads plus reserve requirements.

Although the proposed ACAP obligation is essentially an extension of the traditional “obligation to serve” under the integrated utility structure, it would be a completely new element to the California market design. The CAISO therefore believes that the ACAP obligation should be phased in over a period of roughly two years. For the ACAP obligation to be effective it requires

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1 The term “load-serving entity” or LSE refers to any entity that provides electric energy to end-use consumers. While there are some non-utility electric service providers (ESPs) that serve end-use consumers under the direct access provisions of the California restructuring, the largest LSEs in California are the three Utility Distribution Companies (UDCs). The UDCs are the distribution system operators in their respective service territories as well as the default electric service providers for consumers who have not chosen a non-UDC direct access provider. The proposed ACAP obligation would of course apply to all LSEs. Moreover, since the CAISO transacts directly only with Scheduling Coordinators (SCs), the ACAP obligation would be applied through the SCs who schedule for LSEs.
adequate lead time to enable LSEs to arrange a portfolio of supply arrangements and demand management capabilities to meet their needs. An ACAP requirement imposed without adequate lead time could place the LSEs at a severe disadvantage in negotiating with suppliers. We therefore propose an interim approach to take effect on October 1, 2002, whereby CAISO ACAP procurement would supplement whatever ACAP quantities the LSEs could procure and would thus provide an orderly transition to a fully effective ACAP obligation at a later date, approximately October 1, 2004. The proposed interim approach is described in detail in Part 2 of this section.

Each LSE’s ACAP obligation would be calculated on a monthly basis as a fixed margin above the next month’s forecast peak load (e.g., in the area of (1.15) * forecast monthly peak load). (Details to be developed for how the most accurate monthly forecast of each LSE’s peak load is determined.) The obligation may be met by a combination of own generation, firm energy contracts (including contracts obtained by the State on behalf of consumers served by the UDCs), capacity contracts, and physical demand management (as opposed to financial arbitrage between the forward and real-time markets). Prior to the start of each month, the LSE would demonstrate to the CAISO that it has secured adequate capacity for the coming month and would be required to identify the relevant “ACAP resources” and associated MW quantities. The LSE would be assessed a penalty for any shortfall (to be determined; this may be in the area of about $70/MW-day or $2,000/MW-month).

One clarification is important up front. As the title “Available Capacity” suggests, the ACAP obligation differs from the “Installed Capacity” or ICAP obligation common to the eastern ISOs by virtue of the ACAP’s availability requirement. This means that a resource designated as an ACAP resource by a LSE must be fully available to the CAISO (for the amount of contracted capacity) via a combination of firm forward energy schedules plus bids into CAISO capacity, unit commitment and energy markets, and must respond to CAISO dispatch instructions. In the event of a plant outage or derate other than planned maintenance, the supplier would be responsible for providing a substitute resource or paying for replacement energy, would be charged the ACAP shortfall penalty and, if the supplier does not report the outage to the CAISO in a timely manner, would be assessed penalties for failing to follow dispatch instructions if it was issued a CAISO dispatch instruction. In summary, the CAISO verifies each LSE’s compliance with the ACAP obligation on a monthly basis based on its demonstration of adequate contracts and designation of specific resources, and then verifies compliance for designated ACAP resources on a daily basis based on their availability.

Ideally this feature should be in place by 9/30/02 when the FERC June 19 mitigation measures expire. This time frame does not appear practical, however, and therefore the CAISO proposes the interim arrangement described in Part 2. LSEs would become fully responsible for meeting their ACAP obligations approximately two years later, as of operating day 10/1/04.

While the ACAP obligation should serve as an incentive to invest in new generation, the CAISO does not see this as the only reason to create the obligation, particularly since the experience of other ISOs suggests that the associated capacity payments are typically discounted in the financial analysis of a proposed generation project. Rather, the main purpose of the ACAP

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2 We expect that LSEs would procure portions of their ACAP obligations on different time horizons, perhaps up to 90 percent on an annual basis, 5 percent seasonally, and 5 percent monthly. It is an open question whether the CAISO should require and verify LSE ACAP procurement on these longer time frames, or simply rely on monthly verification and leave the portfolio structure to the LSEs.

3 Note: Apart from an explicit penalty for uninstructed deviation, resources that have no forward schedule do not incur a cost for replacement energy in real-time since the cost of a negative uninstructed deviation exactly offsets the energy payment for the dispatch instruction.
obligation is to explicitly assign the responsibility for ensuring adequate capacity is available on a daily basis, a crucial element that was missing in the original design of the restructured markets. In practice, of course, we expect that LSEs would meet their obligations through a portfolio of assets and contracts, which should in turn stimulate investment in new capacity.

Issues remaining to be addressed include:

- Should there be an annual planning process in which LSEs present their 12-month load forecasts and resource plans? Most probably an annual forecast with monthly updates would enable the LSE to secure cheaper annual ACAP for its minimum monthly obligation, and arrange for the balance on a monthly basis. Such a process would also provide greater confidence to state policy makers that California consumers are protected from the impacts of capacity shortages.

- If the CAISO’s verification for a given month indicates a shortfall, should the CAISO take any action to procure additional capacity? Should the CAISO be the supplier of last resort for ACAP, even in the long term? In theory it should be possible to define the ACAP obligation and penalty structure so that there would not be a shortfall that threatens reliability, in which case the CAISO would not need to procure additional capacity. The CAISO must, however, be confident that it can meet its responsibility for reliable operation of the grid. In addition the CAISO must be concerned about the exercise of market power in its markets, which is part of the rationale for a 115% ACAP requirement rather than a level of 107% to meet reliability requirements.

- Is there a need for a market for ACAP to facilitate trading among LSEs to meet their obligations? Clearly this is needed for the interim approach, as discussed in the previous section, since it would entail the CAISO procuring ACAP to meet the aggregate ACAP shortfall of the LSEs. It is not clear whether an ACAP market is desirable in the long term.

**Forward Congestion Management (CM)**

Forward CM is one element of this proposal in which the approach differs significantly from the approach the CAISO had previously described in the January 2001 Congestion Management Reform (CMR) proposal. Before describing the current proposal, it is important to explain some of the basis for departing from the approach proposed in the CMR project.

In the CMR proposal forward CM was to be performed using a commercial network model compatible with the way the California system is operated in real time, i.e., based on area nomograms and operating procedures derived from engineering studies. These nomograms and operating procedures would be used to partition the CAISO-controlled grid into a relatively small number (less than 20) of “Locational Pricing Areas” or LPAs, connected to one another by potentially constrained interfaces. The CMR approach was thus an extension of today’s zonal system, with more numerous LPAs designated as new zones to fully reflect the prevailing operating constraints, and with loop flows among the LPAs instead of today’s purely radial system.

Upon reexamination of the CMR proposal in the present MD02 project, we find that some of the crucial assumptions underlying the LPA concept developed in CMR break down. In particular, it is not possible to ignore the locations of resources within a given LPA since these resources will have different effects on (1) constraints within the LPA, so that we can not ignore intra-LPA congestion in forward CM, and (2) constraints elsewhere in the grid outside of the LPA, i.e., all resources within an LPA will not have equivalent effectiveness factors for mitigating congestion elsewhere in the grid. Moreover, the network topology in many areas of the grid in not compatible with the CMR notion of well-defined LPA boundaries with a few well-defined
interfaces between LPAs. Thus it is not possible to simply increase the number of LPAs until we eventually reach a number where the LPA concept works. In such areas it will be necessary to perform CM on a detailed model of the network in order to ensure feasible schedules. In practice this leads to enforcement of individual local transmission constraints using a detailed model of the network, instead of enforcing nomogram constraints as was envisioned in the CMR proposal.

Based on the preceding observations, the MD02 team is proposing that forward CM should adjust generation and load schedules to clear congestion using an optimal power flow algorithm (OPF) and a Full Network Model (FNM), having 3000 busses and intertie points within the CAISO-controlled grid, plus a reduced external network representing the rest of the WSCC system to capture external loop flows. Using the FNM for CM does not, however, mean that we must use 3000 busses for all scheduling and settlement purposes. Rather, it should be possible to aggregate busses to create “trading hubs” to facilitate energy trading, and “demand zones” to simplify load scheduling and settlement. At the time this document is being drafted, the MD02 team has not yet developed a more specific proposal for how to define trading hubs or demand zones, so we can not provide additional detail at this time. We expect this to be a topic for discussion with market participants in the focus groups. The crucial point is that we can perform CM using a network model that correctly manages all the congestion inherent in preferred schedules, while still allowing for commercial simplification through aggregation of nodes.

The proposed CM approach ensures that final schedules are feasible with respect to all transmission constraints as well as generator ramping and other performance constraints, and renders the current distinction between inter-zonal and intra-zonal congestion irrelevant. The last point deserves additional emphasis. A crucial assumption in the original zonal congestion management design was that intra-zonal congestion would be infrequent and have relatively small cost impacts. The idea was that a new zone would be created as soon as the frequency and cost of intra-zonal congestion exceeded a certain threshold. In fact, however, the distinction between inter-zonal and intra-zonal constraints and their management in separate congestion management steps have led to severe problems at various times in the CAISO’s history.

Moreover, not all these problems are conducive to creation of a new zone, since a workable new zone must have a fairly simple physical topology, i.e., with one or two constraining interfaces connecting it to the rest of the grid. Thus, in reality the “simplicity” of the zonal system only appears so because the complexity is assumed away, allowing market participants to ignore it in scheduling while the CAISO must manage it through real time adjustments and periodic modifications to the rules to mitigate novel gaming strategies as they arise. The MD02 team believes that it will be far simpler, and more transparent, to design forward CM to be as consistent as possible with the real-time operating needs of the grid. In this regard eliminating the inter-zonal-intra-zonal distinction will increase the simplicity, transparency and accuracy of congestion management.

Another significant impact of the proposed CM approach is its implications for forward energy trading. A separate day-ahead energy market along the lines of the former Power Exchange (PX) is a viable option in its own right regardless of the CAISO’s CM approach, and the CAISO is currently exploring whether it is desirable to operate such a market itself or to help facilitate

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4 The proposed concept of feasibility does not, however, require that final schedules reflect actual levels of load and generation expected in real time. Any shortfall between final schedules and the CAISO’s load forecast is addressed by the CAISO’s day-ahead unit commitment, discussed below.

5 For example, ignoring intra-zonal constraints in establishing forward schedules has allowed “the DEC game,” whereby suppliers can over-schedule a constrained intra-zonal pathway and then exercise local market power to receive a premium payment in real time to eliminate the overload.
such a market operated by another entity. At the same time, the proposed CM approach will effectively create a day-ahead energy market that runs simultaneously with CM, as the following logic explains. The existence of a separate PX-type energy market would probably, however, decrease the volume of energy trading that occurs within the CAISO’s CM process.

The threshold design decision is to perform forward CM using a network model that is more complex than today’s model of three zones with no loops among the zones. The following logic thus applies whether we are considering the model with 12 LPAs as proposed in CMR, or one with 3000 busses as proposed here, or something in between. The key point is that to manage congestion in such a model using a market-based approach with submitted bids – which reflect SCs’ willingness to pay congestion charges rather than be curtailed – it will be impractical most of the time to keep each SC’s schedule in balance. Rather, it will be necessary for the CAISO either to create energy trades, effectively treating adjustment bids as energy bids, or to try to preserve the market separation rule, continually run out of adjustment bids, and be forced to make pro rata curtailments.

In summary, under the proposed CM approach SCs will submit Energy/Adjustment Bids on their generation and load schedules. Due to the complexity of the network model used for CM, the CAISO will need to create inter-SC trades to clear congestion. As a result, balanced schedules for each individual SC become an option rather than a requirement. SCs who want to preserve physical bilateral contracts can submit extremely high adjustment bids or no bids at all, thus becoming price takers for congestion charges, and hedge their congestion risks with FTRs. In addition, under this approach SCs will be able to submit demand bids unmatched by supply, or supply bids unmatched by loads, and the simultaneous energy/CM algorithm will execute all economic trades and clear the market in a manner that respects transmission and generator performance constraints. Thus bid-based CM using a complex network model ultimately undermines the rationale for a balanced schedule requirement, while still accommodating physical bilateral scheduling for those market participants who wish to schedule in this manner.

The proposed forward CM approach also addresses the need for a day-ahead energy market, as required by FERC in its December 15 order, since it accepts bids from unmatched loads and resources clears all economic bids, subject of course to constraints. In so doing the forward CM approach results in nodal energy prices at each of the 3000 internal busses and intertie points. Forward congestion prices then become the difference between nodal energy prices. This will require some redesign of the existing FTR structure, as described below.

As noted above, using the Full Network Model and generating 3000 nodal prices for forward CM does not require that all transactions be settled based on 3000 prices. As is typical of other ISOs that utilize a FNM for forward CM, the CAISO can create a small number (perhaps 15-20) of demand zones for the purpose of load scheduling and settlement and as trading hubs. SCs would be required to schedule loads to the level of the demand zone, and the CAISO would allocate these loads to specific nodes using “bus load distribution factors” (BLDF, not to be confused with transmission distribution factors, also known as shift factors) prior to running CM. The FNM would be used to run CM and the nodal prices would determine congestion costs, but then prices could be aggregated to the demand zone or trading hub level for settlement purposes. An issue to discuss is whether the demand zones and trading hubs should always coincide, or whether it is feasible and desirable to use different criteria to define the two types of aggregates and to have a greater number of one or the other.

Finally, one persistent problem with the CAISO’s congestion management since the beginning has been so called “phantom congestion,” a byproduct of the Existing Transmission Contract (ETC) rights that have existed since before CAISO start-up. In some cases ETCs allow the rights holders to retain scheduling priority on designated transmission pathways up to 20
minutes before the start of the operating hour, which the CAISO accommodates by fully removing ETC capacity from the CM process even though significant portions of that capacity will ultimately be unused by the rights holders and will become available in real time. Ideally the CAISO would like to see all ETCs converted to FTRs or in some other way made fully consistent with CAISO scheduling and congestion management procedures and timeline. If this is not possible, the CAISO may consider offering recallable transmission service (RTS) on a day-ahead or perhaps hour-ahead basis after allocating firm transmission. (RTS was discussed in detail in the January 2001 Congestion Management Reform proposal, which is available on the CAISO web site.)

**Firm Transmission Rights (FTRs)**

If the CAISO proceeds with the forward congestion management design described above, certain changes to FTRs would be appropriate. Today’s FTRs are called “Firm Transmission Rights” and have a physical aspect, namely, the right to associate FTRs with a day-ahead schedule and thereby ensure that that schedule has priority against curtailment in the event of congestion. Today’s FTRs are path and direction specific, and are used in a fully radial fashion consistent with today’s inter-zonal congestion management (and the traditional contract path approach to securing transmission rights). This means that a schedule across an inter-zonal interface is assumed to flow completely over that interface, assuming away any loop flows outside the CAISO-controlled grid. Thus FTRs on a single interface can be used to fully hedge congestion risk for a schedule over that interface.

Under a forward CM approach that uses a FNM, certain changes to the design of FTRs will be necessary to ensure that FTRs can fulfill their intended purpose, i.e., to enable market participants to hedge congestion risks. The changes currently being considered are:

- The nodal energy prices generated by forward CM would be the reference for congestion charges; thus the congestion charge between two nodes would be the difference in the respective nodal prices.
- To allow complete hedging of congestion risks, market participants would be able to obtain point-to-point FTRs (between two specific nodes), point-to-hub FTRs (between any node within a given hub area and the hub itself), and hub-to-hub FTRs (between any two trading hubs). A question to discuss in this regard is the optimal number and location of trading hubs to most effectively facilitate forward energy trading, scheduling, and hedging of congestion risk.
- It may be possible to preserve the day-ahead physical scheduling priority of today’s FTRs, but only for the point-to-point rights. To use the FTRs in this way the SC would need to attach them to a balanced schedule between the two relevant nodes, in the same direction as the FTRs. The point-to-hub and hub-to-hub rights would be financial only.
- Ideally all ETCs would be converted to the new FTRs in such a way that the holders of the existing ETC rights would have to schedule in accord with the CAISO’s scheduling procedures, and these procedures would offer an adequate “tool kit” to enable ETC rights holders as far as possible to achieve the same management of risk that their current rights provide.

A number of questions regarding FTRs remain to be addressed. Some of these are:

- Whether to adopt a “use it or lose it” model for FTRs. There are two meanings to this expression in the context of FTRs. (1) In the CAISO’s existing FTR system, the FTR holder has to use the physical scheduling priority in the day-ahead time frame or lose it; i.e., the FTR holder can not exercise FTR scheduling priority on an hour-ahead schedule. (2)
approach being considered by RTO West, FTRs would be valuable only to parties who actually schedule on the system, and would not have value for an investor who wants to buy the FTRs to earn the associated stream of congestion revenues. The way this is achieved is by allowing payment of congestion revenues only to offset the congestion charges a party actually incurs from scheduling on the system.

Regarding interpretation (1) the MD02 team believes that day-ahead scheduling priority that expires after day ahead is feasible for point-to-point rights if market participants would find this valuable. However, as noted earlier it is also possible to protect a physical bilateral schedule by not submitting adjustment bids on a balanced schedule and becoming a price taker for congestion charges. Thus a physical aspect may add complexity but very little additional value to the FTRs.

Regarding interpretation (2) the MD02 team believes that allowing FTR purchases as an investment will increase participation in the primary auction and result in more competitive prices being paid for FTRs. On the other hand, the use it or lose it provision would likely increase activity in the secondary auction since none of the FTRs would be held off the market by investors. The relative merits of each approach deserve further assessment.

- Whether the new FTRs would be obligations, which impose a cost on the holder when congestion is in the opposite direction of the right, or options only which impose no cost when congestion is in the opposite direction.
- Whether there are compelling reasons to also create path-specific or “flowgate” rights, in addition to the point-to-point, etc., described above. An FTR system that has both types of rights would be more complex, since the basis for assessing congestion charges is different for each type.

**Forward Spot Energy Market**

As discussed in the section on Forward Congestion Management, the proposed approach necessitates a certain level of energy trading between SCs through the need to clear congestion using submitted bids. It also enables day-ahead energy trading by allowing market participants to submit unbalanced demand and supply bids, which the CAISO’s CM procedure would then clear in the most efficient manner subject to transmission constraints. Thus a forward spot energy market is implicit in the redesign of CM. Nevertheless, it may still be desirable to create a separate PX-type energy market apart from CM, which could be operated by the CAISO in a step that runs prior to CM, or by another entity entirely. Such a market would probably decrease the volume of energy trading that occurs within the CM process since SCs with unmatched load or generation would transact some if not all of their demand or supply in this prior market, thus reducing the volume of unmatched bids that appear in CM. The relative merits of creating this type of market are still being assessed.

**Residual Day-ahead Unit Commitment**

The Unit Commitment envisioned in the MD02 effort is called “residual” because its intent is to supplement the self-commitment of resources by market participants, not to replace that self-commitment. Thus the proposed Unit Commitment would occur after day-ahead preferred schedules have been submitted, when the CAISO would assess the adequacy of self-committed resources and scheduled firm imports to meet the CAISO’s forecast of next day’s system load and local reliability needs. The CAISO would then commit such additional resources whose start-up times require day-ahead notice to ensure that enough capacity is on-line to meet the next day’s forecasted needs at both the system and local level. All resources that had been
designated ACAP resources by LSEs would be required to bid into this unit commitment market if they have not already been scheduled to run. Non-ACAP resources would be allowed but not required to bid into unit commitment.

The MD02 team is considering designing the residual UC along the lines laid out in the CAISO’s proposal for compensating long-start-up time units subject to the current must offer obligation. In particular the following provisions are proposed for consideration:

- A unit committed by the CAISO would lose its guaranteed start-up and no-load payment if it has an hour-ahead energy or A/S schedule, or real-time uninstructed deviation.
- Guaranteed payment for start-up and no-load cost would be net of any real-time market revenues over the commitment cycle (no less than 24 hours, and no more than 48 hours).

The MD02 team expects that the combination of the ACAP obligation and the CAISO’s residual UC capability will allow the CAISO to eliminate the current RMR contracts, except perhaps for Condition 2 units. This issue needs further assessment however before we can reach a definite conclusion.

Changes to the Ancillary Services Markets

This topic is within the scope of the MD02 effort and must be addressed. At the time this document is being prepared, however, the team has not given it sufficient attention to describe the options here.

Changes to the Structure and Timing of the Hour-ahead Market

This topic is within the scope of the MD02 effort and must be addressed. At the time this document is being prepared, however, the team has not given it sufficient attention to describe the options here.

Real-time Economic Dispatch using Full Network Model

This element was fully discussed in the context of the CAISO’s CMR project and was described in the CMR proposal issued in January 2001. Consistent with the CMR recommendation the MD02 team proposes a security-constrained economic dispatch for the real time market, to fully take into account all transmission constraints, local reliability needs, loop flows, generator operating constraints, and imbalance energy needs. This approach would produce nodal real-time energy prices, which would be paid to supply resources but could be aggregated for settling load deviations. This approach is a logical extension of the real-time market pricing changes being introduced in the CAISO’s filing of the permanent Target Price fix.

Real-time Bid Mitigation for Local Reliability Needs

Real-time bid mitigation becomes necessary when the merit order sequence of dispatching real-time energy to meet system imbalances fails to resolve intra-zonal congestion or satisfy a local reliability need. In these cases the CAISO has to take bids out-of-sequence (OOS) to address the local problem. Suppliers who are aware of their strategic locations in such situations are said to have locational market power, and often exploit this by bidding extremely high to increment their output (INC), or extremely high in the negative direction to decrement their output (DEC), knowing that the CAISO must dispatch them. To limit exploitation of locational market power we expect to propose specific mitigation measures similar to those approved by FERC for other ISOs. Such measures are appropriate regardless of the granularity of forward
congestion management or real-time locational pricing, i.e., under both full nodal pricing and a more aggregated approach.

**Damage-control Price Cap on CAISO Markets**

Without the price mitigation provided by the FERC market mitigation orders, the spot markets will be vulnerable to occasional extreme peak prices. All other ISOs have some level of damage-control price cap to limit the adverse cost impacts of an unusually severe price spike. The MD02 team proposes that such a cap be established for the CAISO markets, but has not yet developed a recommendation on the level of this cap.

**Part 2. Elements needed by September 30, 2002, when the FERC mitigation measures expire**

Although it would be ideal to have all market design elements in place by September 30, 2002, the CAISO does not believe this goal is feasible given the time it takes to finalize the design details, develop tariff language, allow 60 days for FERC approval, and develop and test all required software. The MD02 team has therefore tried to identify the most critical elements needed to ensure stable markets and reliable operation after the FERC mitigation measures expire. The FERC mitigation provisions have been helpful in limiting the exercise of market power; specifically, the must-offer obligation has targeted physical withholding while the price cap in non-emergency hours has targeted economic withholding. Thus the objective of the MD02 team is to identify those elements that would be most effective in ensuring adequate supply at competitive prices after September 30. These elements would then comprise the Phase 1 FERC filing mentioned earlier in this document.

To place these critical elements in context, the reader should keep in mind that the CAISO Board has already approved the filing of Real Time Market Pricing changes (i.e., the permanent “Target Price” fix) and Interim Intra-zonal Congestion Management (including real-time bid mitigation for local reliability needs). We assume these elements will be in operation before September and will complement the additional elements identified below. The additional critical elements are:

1. Interim CAISO Available Capacity (ACAP) procurement that will transition to fully effective ACAP obligation on load-serving entities (LSEs),
2. Capability for day-ahead energy trades to shape next-day supply needs (e.g., the day-ahead energy market as directed in the December 19 FERC order),
3. CAISO day-ahead residual unit commitment, and
4. Damage control price cap on CAISO markets.

[Note: The combination of above elements would likely allow and be enhanced by some modifications to the CAISO’s A/S procurement. Such modifications would likely be part of the Phase 1 FERC filing, but a proposal in this area has not been developed for the present draft.]

Of the elements above, items 3 and 4 are part of the Comprehensive Design discussed in the previous section. The remainder of this section discussed items 1 and 2.

**Interim CAISO ACAP Procurement**

The objective in designing a transitional measure is to start as close as possible to the desired long-term design, so that the transitional elements will simply phase out as the LSEs assume
greater responsibility for their full ACAP obligations. Thus the transitional measures proposed here are intended to supplement, rather than replace, the ACAP procurement of the LSEs. As described below, the CAISO would procure ACAP only as needed to meet a shortfall in LSE-supplied ACAP, and the cost of CAISO procurement would be charged to LSEs in proportion to their shortfall. In addition, the CAISO procurement would need to have effective market power mitigation provisions, otherwise the near-term negotiating disadvantage of the LSEs would simply transfer to the CAISO.

The MD02 team expects that this transitional approach will need to be in place for about two years. A two-year transition would enable LSEs to plan their supply portfolios over a multi-year planning horizon and to have effective bargaining power vis-a-vis suppliers in negotiating contracts of varying lengths to meet their obligations. These transition measures would therefore take effect on October 1, 2002, with the expectation that LSEs would become fully responsible for the amount of their ACAP obligations on October 1, 2004.

During the two-year transition we propose the following arrangement. Readers may recall a similar proposal in the CAISO’s April 2001 Market Stabilization Plan. For some of the design elements below there are options being considered, as noted.

1. The CAISO would offer to contract with generators, both inside and outside of the control area, to provide ACAP to meet system load and locational needs. The CAISO would contract on a monthly basis, based on its own forecasts of monthly peak load, scheduled generation and transmission outages, import availability, etc. In calculating the quantity of ACAP to purchase, the CAISO would start with a target of 115% of monthly system peak load, then subtract capacity under control of LSEs (e.g., the utilities’ retained generation and QF capacity), firm energy contracts and other capacity contracts held by the LSEs or by the State on their behalf, and expected real-time energy available from imports. The CAISO would then purchase ACAP to fill the remaining gap as far as possible. Using this approach the level of CAISO ACAP procurement should decline over time as the LSEs negotiate contract portfolios to meet their needs.

2. LSEs would be required to demonstrate to the CAISO, on a monthly basis, the level of ACAP they have procured, and to identify specific ACAP resources that will be available for CAISO day-ahead commitment and real-time dispatch.

3. During the transition LSEs would not be assessed a penalty for failing to fully procure their ACAP obligations. Instead they would pay a share of the CAISO ACAP procurement cost proportional to their own ACAP shortfall. For example, if the design of the long-term ACAP obligation (to be effective on 10/1/04) calls for a LSE to procure 115% of its next month’s peak load, then starting on 10/1/02 this LSE would be assessed a share of the CAISO’s ACAP costs based on the gap between 115% of the LSE’s monthly peak and the supply the LSE could certify through a combination of its own generation, firm energy contracts (including its share of contracts or other supplies held by the State), capacity contracts (e.g., self-provided A/S), and demand management.

4. ACAP contracts would be awarded through a bidding process, but, recognizing that such bidding will not likely be competitive in the current environment in most months, ACAP prices would be capped at a reasonable level, to be determined.

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6 As an alternative, the CAISO might start with a lower target for its own procurement, perhaps 105%, and increase the target in steps to get to the long-term design target of 115% at a later date.

7 For comparison, $25 per kW-year has been about the average price in the PJM ICAP market. This translates to about $2000 per MW-month or $2.85 per MW-hour on average, although actual costs would likely be higher in peak months than in off-peak months.
5. Option (A). All PGA resources would be required to bid into the ACAP market to the extent they have capacity that is not already committed to bilateral contracts. This provision would be very similar to the current must-offer obligation and would require a FERC order, but unlike today’s must offer it would provide generators with a capacity payment. Non-PGA resources and generating resources outside the CAISO control area would be invited to bid into this market; the latter would have to secure firm transmission to ensure deliverability of any ACAP provided. Option (B). Participation in CAISO ACAP market would be completely voluntary, but to prevent physical withholding the CAISO would need the authority to commit in-state resources on a day-ahead basis even if they did not offer to supply ACAP.

6. The ACAP capacity payment would carry an availability requirement, whereby ACAP resources not self-scheduled in the day-ahead market to meet CAISO control area load or self-provide A/S, must be available to the CAISO for the A/S and real-time markets and for day-ahead unit commitment. Any non-availability due to forced outage or derate would subject the resource to penalties as described above. This aspect of the transitional approach would be consistent with the long-term design.

One area still to be addressed is how ACAP resources procured by the CAISO are allowed to bid and participate in markets. In principle, this issue should be resolved in a manner that is consistent with the long-term approach, and that treats LSE-supplied ACAP the same as CAISO-procured ACAP. For discussion purposes, we may consider two cases. For Case 1, suppose the resource is not self-committed in the day-ahead market. A possible approach is to follow the CAISO’s recent proposal\(^8\) for long-start-up time units under the must offer obligation, whereby units for which the CAISO pays start-up and minimum load costs would be fully under the CAISO’s dispatch control for a commitment period of, say, 48 hours, meaning that the resource may participate in the markets only by submitting real-time energy bids to the CAISO. If such a resource bids into A/S or deviates from the CAISO’s instructed operating point it would forfeit its start-up and minimum load payments for that day. However, the resource could be allowed to submit market based bids for energy above minimum load and collect the real-time MCP if dispatched in merit order. The real-time net market revenues would then be set against the CAISO’s start-up and minimum load payment obligations. Should such a resource be needed for local reliability, however, its real-time energy bid would be mitigated to prevent the exercise of local market power.

For Case 2, suppose the resource does appear in a forward schedule or bids and is awarded A/S capacity. In this case the resource is clearly participating in markets other than real-time, and the CAISO’s responsibility for start-up and minimum load costs would be limited to a pro rata share proportional the share of CAISO-dispatched energy in the resource’s total output over the commitment period. As in Case 1, energy bids would be mitigated if the resources is needed out of merit order for local reliability, but not for system imbalance needs.

Another issue to be examined is whether the CAISO ACAP procurement can replace the current RMR contracts for local reliability. At least under Option A above, the resources that are procured today under annual RMR contracts should be available for monthly procurement as ACAP, except perhaps for RMR Condition 2 resources.

In contrast, ACAP would probably not eliminate the need for Operating Reserves (O/R), since capacity available as ACAP would not all be 10-minute responsive as is required for Spinning and Non-spinning reserves. A separate procurement of O/R would most likely continue under this proposal. ACAP may, however, eliminate the need for Replacement Reserve. This and

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other questions regarding changes to the A/S markets are not yet addressed in detail in the present draft.

**Day Ahead Energy Market**

FERC’s December 19, 2001 order directed the CAISO to file a proposal for a day-ahead energy market by May 1. As discussed above, there are several options for how a day-ahead energy market may be structured and operated, and in any event some degree of day-ahead energy trading will need to occur as a consequence of improved congestion management. However, since the CAISO does not expect to be able to fully implement the proposed new congestion management approach by September 30, 2001, the CAISO may need to establish some mechanism to facilitate day-ahead energy trading among market participants by that date. The MD02 team does not yet have a proposal or a set of developed options to include in the present draft.