June 17, 2002

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

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

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

California Independent System Operator Corporation,
Docket No. ER02-___-000

Dear Secretary Salas:

Pursuant to Section 205 of the Federal Power Act,16 U.S.C. § 824d; Sections 35.11 and 35.13 of the Commission's regulations, 18 C.F.R. §§ 35.11, 35.13; and the Commission's December 19, 2001 Order on Clarification and Rehearing,[1] the California Independent System Operator Corporation (ISO)[2] respectfully submits for filing proposed tariff revisions that implement additional elements of its Comprehensive Market Design Proposal.

The ISO submitted its Comprehensive Market Design Proposal (referred to as "MD02"), along with tariff revisions implementing the portions of that proposal that are intended to go into effect in 2002, in a filing made on May 1, 2002 (hereinafter referred to as the "May 1 Filing"). Specifically, the May 1 Filing included tariff revisions for (1) locational market power mitigation; (2) residual unit commitment; (3) modification of the must offer requirement; (4) real-time economic dispatch; (5) use of a single energy bid curve; (6) penalties on generators for failure to comply with dispatch instructions; (7) extension of the current commission mitigation measures; (8) a rolling 12-month

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1 *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator and the California Power Exchange, et al.*, 97 FERC ¶ 61,275 (2001) ("December 19 Rehearing Order").

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

competitive index with pre-authorized mitigation; and (9) a price cap on decremental bids.

The May 1 Filing also included, as Attachment A, a detailed description of all elements of the ISO's Comprehensive Market Design Proposal. In the May 1 transmittal letter the ISO committed to filing the remaining tariff language required for complete implementation of the MD02 proposal in mid June. The present filing fulfills this commitment and provides the tariff revisions needed to implement the longer-term portions of the MD02 proposal. As such, this filing should not be viewed in isolation from the May 1 Filing, but must be read and understood in conjunction with that filing, its Appendix A in particular.

Copies of the enclosed tariff revisions are being provided to parties simultaneous with this filing and will be posted on the ISO website. The ISO will commence a series of technical conferences to explain the proposed tariff revisions and to receive comments from stakeholders beginning in July, 2002. In addition, the ISO proposes – and requests Commission staff participation in – a week-long meeting with stakeholders in the first half of August to try to reach agreement as far as possible on issues that were not resolved at the July meetings. The ISO will publish a schedule for the July meetings in the near future.

I. SUMMARY OF THE FILING AND REQUESTED COMMISSION ACTION

As described in the May 1 Filing, the ISO's proposed comprehensive market design is built around two core elements: (1) an available capacity or "ACAP" obligation on load serving entities, which requires these entities to demonstrate to the ISO on a monthly basis that they have procured adequate resources to meet their expected peak loads and reserve requirements, and which places availability requirements on those resources identified by load serving entities as fulfilling their ACAP obligations; and (2) integrated forward markets (day ahead and hour ahead), based on locational marginal pricing (LMP) at the nodal level, that simultaneously perform congestion management, spot energy trading, ancillary service procurement, and unit commitment. Associated with the second core element are a number of related elements, including day ahead residual unit commitment, redesign of firm transmission rights, real time economic dispatch, and measures for market monitoring and mitigation.

The May 1 Filing also described the ISO's proposed phasing of implementation of the comprehensive market design: Phase 1, targeted for October 1, 2002 implementation, for which tariff language was included in the May 1 Filing; Phase 2, targeted for Spring, 2003 implementation, which will include most of the comprehensive design except for the ACAP obligation, the full network model, and those features of the design that require the full network model (e.g., nodal pricing and the redesign of firm transmission rights); and, Phase 3, targeted for Fall 2003, which will include all elements of the comprehensive market design except for the ACAP obligation. The ISO proposes to make the ACAP obligation fully effective at the beginning of 2004.

Accordingly, this transmittal letter first describes the comprehensive design elements in their fully implemented form. Later sections of this document describe the interim provisions.

To reflect the proposed phasing of implementation in the most efficient way, the tariff language submitted in the instant filing is structured as follows:

(1) Attachment A which incorporates the changes to the ISO Markets (day ahead, hour ahead, and real time) that reflect full implementation of the comprehensive design. Attachment A also incorporates temporary provisions (Section 32) that will apply until the full network model, nodal pricing, and the redesign of firm transmission rights are implemented. The ISO requests an effective date for these temporary provisions of the later of May 1, 2003 or when the ISO announces it is ready to implement Phase 2 of the MD02 long term elements.

(2) Attachment B are changes to Section 9.4.1 and 9.4.2 which will enable the ISO to sell Firm Transmission Rights (FTRs) for durations of less than one year, to cover the period from May 31, 2003 when the current release of FTRs expires until the new FTR design is implemented in Phase 3. The ISO requests to make these effective January 1, 2003.

(3) Attachment C which incorporates the remaining changes to Section 9 of the ISO Tariff regarding FTRs. The ISO requests an effective date for these provisions of the later of October 1, 2003 or when the ISO announces it is ready to implement the full network model.

(4) Attachment D which incorporates the changes to implement the Available Capacity Obligation (ACAP). The ISO requests an effective date for these provisions of January 1, 2004.

Attachment E to this filing is a table that summarizes the Tariff provisions that have been added, deleted, or modified consistent with the blacklines in Attachment A. Similarly, Attachment F is a summary of the changes related to FTRs, and Attachment G summarizes the changes to incorporate ACAP. Attachment H is the Advisory Forward Energy Curtailment proposal. Attachment I is the Reliant Companies' motion for the establishment of a capacity market in California. Attachment J is the notice of filing. In order to present the detailed tariff language to the Commission and Market Participants at the earliest possible time, the ISO has only attached the blacklines showing the proposed tariff revisions with this submission. The ISO will work expeditiously to complete the clean tariff sheets and file them as soon as possible. The ISO respectfully requests waiver of the Commission's filing requirements to permit the filing to proceed in this manner. Given the importance of these redesign issues and the need to proceed expeditiously, the ISO submits there is good cause to support to waiver which will allow the Commission's consideration of the substance of the redesign to proceed immediately.

II. DESCRIPTION OF THE TARIFF REVISIONS

A. ELEMENTS OF THE COMPREHENSIVE MARKET DESIGN

1. Design of the Integrated Forward Markets

a. Forward Congestion Management and Energy Market

In the day ahead and hour ahead markets, the ISO proposes to use an accurate model of the ISO transmission grid to adjust generation and load (and import and export) schedules to mitigate transmission overloads, ensure local reliability, and, in the process, produce locational marginal energy prices at each node of the grid.[3] These forward congestion management (CM) procedures will use a Security Constrained Unit Commitment (SCUC) optimization algorithm and a Full Network Model (FNM), which will include all transmission network busses and transmission network constraints as well as an external equivalent network representation of the rest of the WSCC system to capture external loop flows. The proposed CM approach ensures that final schedules are feasible with respect to all transmission constraints, as well as generator ramping and other static and inter-temporal performance constraints, and eliminates the current distinction between inter-zonal and intra-zonal congestion.

The proposed CM approach will eliminate the balanced schedule requirement and the Market Separation Rule that have characterized the ISO forward markets to date, and thus will effectively create forward energy markets that run simultaneously with CM. (Ancillary service markets and unit commitment will also run simultaneously with CM, as described below.) Scheduling Coordinators (SCs) will submit "three-part" Energy Bids (including start-up and minimum load components as well as the energy curve) along with their preferred generation and load schedules, and these bids will be used to clear congestion, to enable loads and resources to buy and sell energy, to procure ancillary services and to perform unit commitment. SCs may also submit capacity bids for ancillary services. SCs who so desire will still have the ability to submit balanced generation and load schedules in the forward markets, but this will be an option rather than a requirement. SCs that want to preserve physical bilateral contracts could submit such schedules using the day ahead scheduling priority of an appropriate

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3 The ISO proposes to develop and utilize an AC Optimal Power Flow (AC-OPF) application for real-time economic dispatch and for the integrated forward congestion management, energy, ancillary services and unit commitment markets. Compared to a DC-OPF, developing an AC-OPF is a more complex endeavor, but offers significant benefits. In particular, the AC-OPF internalizes losses, which increases the accuracy of dispatch of resources by calculating the effects of losses on congestion in the network. The AC-OPF also increases the accuracy of dispatch by incorporating voltage and stability constraints, which a DC-OPF cannot do. Today the NY ISO uses an AC-OPF with losses internalized, while PJM uses a DC-OPF and accounts for losses through static loss factors. Because of the added complexity of the AC-OPF, the ISO proposes to keep the Commission informed on a regular basis of its progress in developing the application, and will be able to fall back on a DC-OPF approach should the AC-OPF effort appear to delay the MD02 implementation timetable.

firm transmission right (FTR), or could schedule as price takers for congestion by not submitting Energy bids in association with the balanced schedule. SCs will also have the ability to self-provide ancillary services as they do today.

The proposed forward CM approach thus meets the Commission's requirement for a day-ahead energy market, since it accepts bids from unmatched loads and suppliers and clears all economic bids, subject to constraints. In so doing, the forward CM approach results in nodal energy prices at each of the internal busses and intertie points, and forward congestion prices are defined as the difference between nodal energy prices.

The DA market process will be modified to eliminate the revised preferred iteration currently in place. With a formal DA energy market in which all economic energy trades are executed, there is no need for a second iteration. The ISO proposes to leave the deadline for receiving preferred energy bids and schedules at 10 A.M., and will publish final DA energy schedules at 1 P.M. after running both the integrated DA market and the DA Residual Unit Commitment (RUC) procedure (as described below).

b. Ancillary Services and Unit Commitment

The ISO proposes that Ancillary Services (AS) be procured simultaneously with the energy market. More precisely, the Security Constrained Unit Commitment (SCUC) application used to run the integrated day-ahead and hour-ahead markets will perform energy trading, congestion management, AS procurement, and unit commitment. Suppliers will submit capacity bids for AS in addition to their energy bid curves, and the SCUC application will perform a bid-cost minimization taking both capacity and energy bids into account. The resulting AS clearing prices will reflect both capacity bids and energy opportunity costs, where the energy opportunity cost of a resource reflects what the resource would have earned above its energy bid if it were dispatched for energy instead of selected to provide AS, i.e., the difference between the clearing price for energy at a particular location and the energy bid of the particular resource at the loading point of its energy schedule, so long as the energy bid associated with the capacity in reserve is less than or equal to the energy clearing price.

AS requirements may be determined on a system or local basis, depending on forecast congestion conditions. Just as today, high-quality services may be substituted for lower quality services; for example, spinning reserve can substitute for non-spinning reserve. AS will be procured subject to the physical capability of the resource, based on ramp rate and regulating limits. AS may be provided by imports, subject to today's general system-wide limits and the implications of any locational AS requirements that apply. AS imports will compete for transmission capacity with energy schedules in the forward markets.

The unit commitment aspect of the SCUC-based markets will consider three-part bids (start-up cost, minimum-load cost, and incremental energy curve), as well as resource operating constraints, to determine the optimal commitment of resources to meet energy, AS and congestion management requirements.

c. The Hour Ahead Market and Real Time Pre-dispatch

The ISO proposes to run an integrated hour ahead (HA) market that is the same in design and procedure as the DA market, including an HA RUC procedure that enables the ISO to issue unit commitment instructions to quick-start units that are not scheduled against HA demand but are expected by the ISO to be needed in real time based on forecast. The closing time of the HA market will be moved closer to real time than it is today, to T-60 minutes, and final HA schedules will be published by T-45 minutes. In the HA CM procedure, if submitted bids are insufficient to relieve congestion the ISO will give priority to final DA schedules over new HA schedules.

Following the ISO's determination of final HA schedules, the ISO will utilize energy bids left over from the HA market that are designated as hourly only (*i.e.*, not able to make mid-hour changes) as well as hourly supplemental bids (*i.e.*, imports), and will issue pre-dispatch instructions for imbalance energy to meet the next hour's load forecast. Imports that are pre-dispatched for the entire hour will be guaranteed their bid price. To the extent the 10-minte price falls below their bid price, the difference will be paid as uplift. In-state hourly generation that is pre-dispatched is eligible to set the MCP in each 10-minute interval in which there is a system need for the energy. If system conditions change and the hourly in-state generation is no longer needed, payment will be limited to the RT MCP.

2. Residual Unit Commitment (RUC)

The RUC procedure is intended as a reliability procurement only, not as a separate market. In the near term – until the ISO begins to operate forward energy markets – the RUC will be more market-like than its long-term design, in the sense that participation in the near term will be open to resources that are not obligated to participate, such as imports. With the advent of forward ISO energy markets and ACAP the ISO will limit participation in RUC to resources that are under an availability or must-offer obligation. Thus the RUC process being proposed in the present filing differs somewhat from the RUC that was included as an "October 1st Element" in the May 1 filing. The fundamental differences are that: (1) intertie supplies will no longer be allowed to bid into the RUC once the ISO starts running a day-ahead energy market (unless these resources are identified as ACAP by a LSE), (2) the ISO's proposed capacity payment for capacity committed in RUC will be eliminated once ACAP is effective, and (3) the ISO will perform both a day-ahead and an hour-ahead RUC process. The hour-ahead RUC will be used to commit quick-start units that were not scheduled and that the ISO expects to need to meet unscheduled load.

Once the day-ahead energy market is operating, the RUC will only consider supply resources that either have been designated ACAP resources by a LSE, or are otherwise subject to a must-offer obligation (i.e., all non-hydro resources that have executed a Participating Generator Agreement). Consistent with the October 1st design filed on May 1, resources committed by the RUC procedure will be guaranteed recovery of start-up and minimum load costs, net of market profits earned during the commitment cycle, and subject to restrictions on self-scheduling and uninstructed deviations. In the long-term design, intertie suppliers can be designated ACAP resources by an LSE, in which case they could be considered by the ISO in the RUC process. Otherwise, intertie suppliers that wish to offer energy on a day-ahead or hour-ahead basis would have to bid this energy into the day-ahead or hour-ahead energy market to be cleared against load bids.

3. Real Time Economic Dispatch

The ISO proposes a security-constrained economic dispatch (SCED) 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. Under this proposal, every ten minutes during each operating hour, the ISO will run the SCED program to determine which resources to dispatch at what operating levels to meet real time needs. This approach will use the Full Network Model (FNM) and will produce nodal real-time energy prices. These real-time energy prices will be paid to generating resources and participating loads, but may be aggregated for settling load deviations, as discussed below. As discussed in the May 1 Filing, the ISO proposes to take an initial, important step toward economic dispatch in real time by clearing overlapping bids in the Imbalance Energy stack and thereby eliminating the "target price" mechanism that has been troublesome since the start-up of ISO operation.

4. Scheduling and Settlement of Loads

Both generators and loads must be represented in congestion management at the nodal level, which is necessary to manage all transmission constraints represented in the full network model and calculate nodal prices. In addition, generators will be required to schedule at the nodal level and will be settled at the nodal level both in the forward and real time markets. For loads, however, the business interface will allow them to schedule and settle at either the nodal level or through aggregations of nodes. The ISO currently has defined certain standard aggregations, including approximately 40 "Load Groups" that reflect the boundaries of small utilities and certain meaningful boundaries in the large utilities' transmission systems, as well as "Demand Zones" that are aggregations of some Load Groups, and finally the current congestion zones (NP15, ZP26, SP15) which are aggregations of Demand Zones. Loads can elect to schedule at the nodal level, or at aggregations of nodes including the standard Load Groups and Demand Zones currently defined by the ISO, as well as custom aggregations that can be defined at the request of a market participant to reflect the specific locations of its loads and/or distributed generation.

For the purpose of running the integrated forward market using the full network model, loads that are scheduled at an aggregated level will be allocated to the network nodes that make up that aggregation using established load distribution factors (LDFs) that will be published by the ISO. For any given aggregation of network nodes, different sets of LDFs will apply to the forward and real-time markets. However, for each market and each aggregation, the same LDFs that are used to allocate scheduled loads to nodes will also be used as weighting factors to calculate average LMPs for the aggregation, to be used for settlement of aggregated loads.

5. Firm Transmission Rights

Under the MD02 proposal, FTRs will be based on a point-to-point (source-to-sink) design that is consistent with the new approach to congestion management (CM) and with the functions envisioned for transmission rights in the Commission's Standard Market Design (SMD). The ISO will also offer Network Service FTRs which generalize the point-to-point design by allowing multiple sources and sinks to enhance the flexibility of the FTR hedge, consistent with the Commission's SMD guidelines. The need for a point-to-point FTR instrument is driven by the LMP congestion management approach, which will assess forward schedules for their flows throughout the grid, including external loops, rather than focusing only on specific transmission pathways. Therefore the point-to-point (and network service) FTR will be the primary type of FTR initially, to be supplemented at a later date, when technically feasible, by path-specific or "flowgate" type FTR for some major transmission pathways, similar to the FTRs currently offered by the ISO.

In conjunction with the point-to-point FTR model, the ISO must run a "simultaneous feasibility" assessment to determine the quantities of FTRs that can be released via allocations to holders of existing transmission contract (ETC) rights who choose to convert those rights, to load serving entities, and through the auction process, in that sequence. The simultaneous feasibility assessment uses a power flow model to combine all parties' desired FTRs and determine the set of FTRs that reflect simultaneously feasible scheduling patterns. In the case of allocations to converted ETC rights and LSEs, when not all desired FTRs are simultaneously feasible, pro rata adjustments will be made in such a way as to achieve feasibility with minimal reduction of FTR allocations, while maintaining the priority order of the allocation sequence noted above. The auction process, in contrast, also incorporates parties' bids for FTRs, and then issues the set of FTRs that maximizes auction revenues subject to all FTRs being simultaneously feasible under assumed system conditions. In this way, FTRs are auctioned to the bidders who value them the most.

Another significant change to the FTR design is to utilize an "obligations" approach as the primary design, rather than today's "options" approach. FTR Obligations allow a more complete and more efficient release of rights to the grid than the options approach. Under the options approach, the quantities of FTRs that can be released are limited by the physical transfer capability of the grid. In contrast, in the obligations approach, the quantities released can exceed the physical limits of the grid whenever counter-flows are created, as long as the simultaneous flows of all FTRs are within the physical limits. For this approach to work, however, an FTR holder who does not schedule in accordance with their FTR Obligations must pay congestion charges when congestion is in the opposite direction of their FTRs, because their failure to schedule had adverse impacts on grid users trying to move power in the opposite direction. Ultimately the ISO intends to allow both FTR Options and FTR Obligations in its FTR design, consistent with the Commission's SMD guidelines. Initially, however, the ISO will limit its general FTR release to the FTR Obligations model, which has been proven in the other ISOs that utilize LMP. At the same time, the ISO will be able to give

FTR Options to converted ETC holders if they prefer, utilizing the sequential allocation approach described below.

The ISO proposes the following features of the new design of FTRs:

1. The congestion charge between two network nodes will be the difference in the respective nodal prices.

2. To allow hedging of congestion risks to be as complete as possible under the LMP model, the ISO will create "point-to-point" FTRs, where a "point" may be a single node or an aggregation of nodes, such as a Trading Hub or a Load Aggregation Point.

3. Day ahead scheduling priority of today's FTRs will be preserved. Scheduling rights not exercised by the FTR holder in the day ahead market will result in the associated transmission capacity being released to other users in the day ahead and subsequent markets.

4. FTR financial rights will be paid or charged in the day-ahead market.

5. There may be hours when congestion revenues collected by the ISO do not exactly equal the net payments due to FTR holders. The ISO will create a Balancing Account to accumulate excess revenues when they occur, and will use these to compensate revenue shortfalls through monthly and annual clearing processes.

6. The primary form of the new FTRs will be "obligations," which impose a cost on the FTR holder when congestion is in the opposite direction of the FTR, in contrast to "options" which impose no cost when congestion is in the opposite direction.

7. The ISO proposes to release FTRs based on three different term lengths: long-term (3-year), medium-term (1-year), and short-term (monthly). The quantities of the first two releases would be based on a percentage (30% for the 3-year FTRs and 45% for the 1-year FTRs) of the lowest actual level of Available Transmission Capacity in the most recent 12 months before the auction (excluding hours of scheduled maintenance or forced outage), whereas the monthly quantities would be determined based on expected system conditions for the coming month.

8. To enable loads to hedge the risks associated with congestion charges, the ISO proposes to allocate FTRs to LSEs based on the historic quantities and geographic distribution of their loads and supply resources. The ISO will then run an FTR auction to allocate any transmission capacity that remains after LSEs and converted ETC holders receive their shares. FTR auction revenues generated by the sale of such capacity will be paid to Participating Transmission Owners (PTOs) to be applied as an offset to the Transmission Access Charge (TAC). LSEs that receive an initial allocation of FTRs may participate in this auction as buyers or sellers, and the auction revenues generated by the sale of LSE-held FTRs will be paid to the selling LSEs.

9. Ideally, all ETCs would be converted to the new FTRs, so that all users of the ISO Control Area would be subject to the same scheduling procedures and time line, and the same congestion management approach and FTR model.[4] The ISO cannot compel such conversion, however, but will design its FTRs to provide an adequate "tool kit" that makes it attractive for ETC rights holders to convert by enabling them as far as possible to achieve the same management of risk that their current rights provide. Even so, the ISO expects that some ETCs will not convert initially and therefore the ISO will provide for the reservation of transmission capacity for ETC holders.

10. Based on the design features and other considerations described above, the ISO proposes to perform the following sequence of steps in allocating transmission capacity to: (1) ETCs that do not convert to FTRs; (2) ETCs that do convert to FTRs; (3) LSEs; and (4) market participants who wish to bid for FTRs. Each step requires the ISO to run a simultaneous feasibility assessment on the relevant set of desired rights, after fixing the allocation of rights that resulted from the previous step.

(a) Step 1. This step is not really an allocation of transmission capacity, since non-converted ETCs will be honored by the ISO in its day-to-day scheduling procedures. The purpose of this step is to calculate the amount of transmission capacity that must be set aside and made unavailable for the subsequent allocation and auction steps, so that the ISO can issue optimal quantities of FTRs. The ISO proposes to perform this calculation based on the historic usage patterns of the non-converted ETCs. For this step, the ETC holders will need to specify the sources and sinks (*i.e.*, a balanced schedule) that best reflect their typical use of their ETCs. The ISO would then perform a simultaneous feasibility assessment of all the non-converted ETCs, treating them all as options rather than obligations, to determine the collective impact of the ETCs on the grid and remove this amount of transmission capacity from consideration in subsequent FTR allocation and auction steps.

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[4] The ISO has elsewhere discussed its concerns about accommodating non-converted ETCs in the LMP congestion management market. See the ISO's May 30 Comments on the Commission's Standard Market Design Options Paper, and the ISO's Answer to Protests on the May 1 Filing, which is being filed concurrently with the present filing. Of particular concern is the ability of ETC holders to reserve unscheduled capacity beyond the close of the day ahead and hour ahead market, regardless of whether they actually use this capacity in real time. Under the ISO's existing zonal congestion management market, the resulting "phantom congestion" undermines efficient allocation and pricing of transmission. Under the MD02 proposal the effect is worse, as phantom congestion undermines the important balance of price incentives between the forward and real-time market by reducing the real-time congestion risk associated with under-scheduling in the forward market. The ISO is also concerned that reservation of ETC capacity may drastically reduce the transmission capacity available for FTR release. Currently the ISO reserves ETC capacity for the specific pathways ETC holders use for scheduling their rights, but under MD02 the ISO must consider the simultaneous feasibility of ETCs on a network in which all constraints are enforced. Unfortunately, consideration was never given to simultaneous feasibility when ETCs were formulated, since the transmission owners were operating in a contract-path world at the time. The ISO has therefore urged the Commission, in the filings cited above, to expedite conversion of ETCs by (1) requiring ETC holders to release capacity that they do not schedule in the day ahead market, and (2) ordering transmission owners not to renew ETCs when they reach their existing termination dates.

(b) Step 2. Allocation of FTRs to converted ETCs.[5] With the capacity identified for non-converted ETCs removed from further availability, the ISO will turn to the set of ETCs that had converted to FTRs and assess their simultaneous feasibility, still using the options approach, unless the holder of the converted ETC wishes to have FTR obligations. As in the previous step, it will be necessary for the holders of the converted ETCs to specify their typical patterns of usage of the ISO Control Area. The FTR Options allocated to converted ETCs will be a combination of 3-year, 1-year and monthly FTRs. The quantities of 3-year and 1-year FTRs will be based on the ETC holder's minimal historic usage of the ETC rights. If a converted ETC holder chooses to receive FTR Obligations, the allocation will be performed in the same way as the allocation to LSEs.

(c) Step 3. Allocation of FTRs to LSEs. For this step, the LSEs will have to provide the grid usage patterns they normally rely upon to serve their loads, and the ISO will run an obligations-type simultaneous feasibility assessment. The transmission capacity reserved for non-converted ETCs in Step 1 and the FTR Options allocated to converted ETCs in Step 2 will not be available in this step. FTR Obligations allocated to the LSEs will be a combination of 3-year, 1-year and monthly FTRs. The quantities of 3-year and 1-year FTRs will be based on each LSE's predominant historical scheduling patterns.

(d) Step 4. Allocation of remaining FTRs through an FTR auction. Unlike the previous three steps where no bids were involved, in this step market participants will bid to buy the FTRs they wish to obtain. Converted ETC holders and LSEs will be allowed to offer to sell some of their allocated FTR Obligations if they wish to do so. (Converted ETC holders that wish to sell or trade their FTR Options will have to do so through the Secondary Market.) The ISO will then run a bid-based obligations-type simultaneous feasibility assessment, protecting those E-FTRs and LSE-FTRs that were not offered for sale, executing trades between buyers and sellers, and awarding the remaining available capacity to maximize the auction proceeds.

11. The ISO does not propose any changes to the current structure and reporting requirements for the secondary FTR market, other than support for the secondary trade of FTRs auctioned in the primary auctions.

Currently, the ISO auctions FTRs on an annual basis every January to be effective for the following April 1 through March 31. Because the ISO anticipates that it will be implementing the new FTR design in the middle of an FTR cycle as currently defined (i.e., during fourth quarter 2003), the ISO will need to sell FTRs that take effect

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5 This step will also include allocation of FTRs to New Participating Transmission Owners. The ISO does not propose to modify the process adopted in Amendment No. 27 under which entities that become New Participating Transmission Owners will, for a limited transition period, receive FTRs for the facilities they turn over to ISO Operational Control. This allocation serves as an inducement to other entities to join the ISO.

on April 1, 2003 and that have duration of less than a full year. Accordingly, the ISO has proposed revisions to existing tariff sections 9.4.1 and 9.4.2 that are reflected in Attachment B.

6. Available Capacity (ACAP) Obligations for Load-Serving Entities

a. Introduction

As described in the ISO's May 1 Filing, and as previously recognized by the Commission, the California electricity market has been plagued by inadequate generation supplies. The supply-demand imbalance is the result of 1) prior to the advent of restructuring in California, a reluctance on the part of utilities to make major investments in generation; 2) an over-reliance on spot-market purchases by the major load-serving entities in the California market; and, as a consequence, 3) a lack of forward contracting necessary to support long-term investment. These conditions have both impaired the development of a competitive generation sector in the California market and jeopardized reliable transmission system operation. As a result of the lack of adequate capacity (and, concomitantly, the lack of forward contracting) the ISO has been forced, at times, to procure large amounts of power in real time at very high prices. Moreover, the difficulty of procuring power in real-time has impaired the real-time reliability of the power grid. On a going forward basis, measures to ensure long-term generation adequacy must be in place and effective if the ISO is to fulfill its statutory mandate to ensure a reliable transmission system.

Therefore, as described in the May 1 Filing and as codified in the attached tariff language, the ISO is proposing to establish an Available Capacity (ACAP) Obligation or requirement on load serving entities (LSEs) within the ISO Control Area.[6] Under the proposed ACAP Obligation, the ISO will verify that LSEs are making the necessary advance arrangements to ensure that adequate generating capacity is available to meet system load and reserve requirements. Specifically, the ISO proposes to require LSEs using the ISO Controlled Grid to demonstrate in advance that they own or have procured sufficient resources to meet their respective share of the ISO's monthly peak load plus operating reserve requirements. On a daily basis, LSEs will then be required to self-schedule or commit sufficient resources to satisfy the ISO's forecast load plus reserves. To the extent the ISO requires additional resources (e.g., because of a significant change in forecast or because of transmission congestion), the other ACAP resources identified by load-serving entities to satisfy this requirement must be made available (for commitment) to the ISO in the day-ahead market.

The primary objective of this requirement is to facilitate and support reliable system operation. In particular, the ACAP requirement should encourage LSEs to shift their energy procurement to forward markets, an objective the Commission and the ISO

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6 Consistent with the current and proposed structure of the ISO's markets, the ISO proposes to impose the ACAP Obligation on Scheduling Coordinators that serve End Use load within the ISO Control Area. Thus, in the attached tariff language, the ISO includes references to, and creates a definition of, "Load Serving Scheduling Coordinators."

have long recognized as critical for stable and reliable operations. Thus, working in conjunction with the proposed RUC process described in the May 1 Filing, the ACAP requirement will facilitate forward procurement, commitment, and scheduling of the resources necessary to satisfy forecast load and support reliable system operation. By moving operating and commitment decisions to the forward market, prices and operations in the ISO's spot market should be stabilized. In addition, on a longer-term basis, the ISO also believes that the ACAP requirement will provide opportunities for LSEs and both generation and demand-based suppliers to contract, thus supporting critical and needed infrastructure investments in California.

As further explained in the May 1 Filing, the ISO proposes to phase in the ACAP requirement for LSEs over a four-year period to give LSEs sufficient time to assemble the necessary portfolios of resources. The ISO also intends to implement the ACAP obligation in a manner that recognizes that ensuring long-term supply adequacy is not a function that the ISO can carry out alone. With respect to state-jurisdictional LSEs, the question of planning for long-term supply adequacy is principally one of state policy. The ISO intends to cooperate with state authorities to ensure that the ACAP obligation complements and furthers state requirements and initiatives to ensure adequate long-term electric supplies.

In addition, recognizing the close relationship between ACAP, Reliability Must-Run Generation ("RMR") and transmission planning issues, the ISO proposes to develop an integrated policy for fairly and equitably addressing these issues. The express purpose of such a policy would be to eliminate, where appropriate, the transmission constraints that give rise to local requirements.

Finally, the ISO recognizes that there are alternative means to achieving reliable system operation. Toward that end, the ISO will work with all interested parties to identify and examine any such proposals and will remain flexible as to the final form of this mechanism.

b. Summary of ISO Proposal

The ISO proposes to require each LSE in the ISO Control Area to identify, on a month-ahead basis, the resources they will make available to serve their forecast peak load for a given month, plus a reasonable reserve margin. The ISO proposes to base such reserve requirements on the established Western Electricity Coordinating Council (WECC) Minimum Operating Reserve Criteria (MORC), translated from daily operating requirements into a monthly requirement, taking into account load forecast inaccuracy a month ahead. LSEs and the ACAP suppliers will have an obligation to schedule or bid the ACAP capacity into the ISO's day-ahead market, and keep the committed ACAP supply available through real-time operation.

LSEs that fail to satisfy the ISO's monthly and daily requirements will have to identify an amount of Credible Demand Resources (CDR) sufficient to cover their deficiency, i.e., an amount of load that the ISO may curtail under Reserve Deficiency conditions. The Credible Demand Resource limit is based on the represented LSE's historical load, and is calculated as the level exceeded in 95 percent of the hours during the corresponding months in a relevant historical reference period. As described in the May 1 Filing and as further discussed below, the mechanisms and arrangements necessary to implement selective load curtailment are not now in place and will have to be developed. As discussed in more detail below, the ACAP-deficient LSE will then have the option of paying no deficiency charge and having its CDR curtailed when the ISO declares a Stage 1 Emergency or paying a deficiency charge and having its CDR curtailed when the ISO declares a Stage 3 Emergency (in which case the CDR will be curtailed before other rotating blackouts).

Such penalties will be set at a rate ($/MW-month for the monthly deficiency charge, and $/MW-day for the daily deficiency charge) necessary to provide incentives for such entities to continually satisfy the ISO's operating requirements. If the LSE fails to identify adequate CDRs to match its ACAP shortfall, the LSE will be subject to more severe deficiency charge rates to the extent of such CDR shortfall.

The ISO's proposal provides that each LSE's ACAP obligation will be calculated on a monthly basis as a fixed margin above the next month's forecast peak load. LSEs will be required to meet this obligation for all hours that have a significant probability (e.g., 95%) of being the peak hour. The obligation may be met by a combination of own generation, firm energy contracts that comport with established WECC standards for firm capacity contracts (including contracts obtained by the State on behalf of consumers served by the IOUs), capacity contracts, and physical demand management. Prior to the start of each month, the LSE will demonstrate to the ISO that it has secured adequate capacity for the coming month, and will be required to identify the relevant "ACAP resources" and associated MW quantities. If deficient, a LSE will be required to submit an amount of "Credible Demand Resources" (i.e., physical load curtailment) equal to the deficiency and, as stated above and described further below, possibly assessed a penalty (Deficiency Charge) for any shortfall.

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 an LSE must be fully available to the ISO (for the amount of contracted capacity) via a combination of firm forward energy schedules, bids to participate in unit commitment, supply ancillary services and energy markets, and must respond to ISO dispatch instructions. In the event of a plant outage or derating other than planned maintenance, the supplier would be responsible for providing a substitute resource or paying for replacement energy, and, if the supplier does not report the outage to the ISO in a timely manner, would be assessed penalties for failing to follow dispatch instructions. It is important to note here the transfer of responsibility from the LSE to the ACAP supplier as we move from the forward market into real time. LSEs have the obligation to procure and submit ACAP in the forward markets. However, once they have satisfied this obligation in the day-ahead market, the ACAP suppliers assume the responsibility of ensuring that the resource is available for dispatch in real time. To the extent an ACAP supplier's ACAP resource is not available, that supplier will face the charges and penalties that otherwise apply to the ISO's real-time market. That is, if unavailable, the supplier will be held responsible for the replacement cost of energy as well as any real-time deviation penalties that may accrue. In addition, the supplier may incur whatever performance penalties are included in the contract between the LSE and its supplier.

However, contrary to certain concerns raised by Market Participants during the development process of ACAP, this does not necessarily mean that the supplier has to physically withhold another resource as back-up or insurance against an outage. If the back-up resource is bid into the real-time market (BEEP stack), even if it is dispatched for imbalance energy, as long as the amount bid into the BEEP stack equals or exceeds the (forced out) capacity of the ACAP resource, the real-time deviation penalty would be waived.

The ISO has always believed that a proactive transmission planning process is an essential element of any long-term market design. At this time, the ISO is not convinced that the implementation of locational marginal pricing and other features of the new market design will create, by themselves, sufficient incentives for transmission expansion. Therefore, the ISO will continue to identify and advocate for the necessary expansion of the system. In particular, the ISO proposes to finalize by the end of 2002 its new methodology for evaluating economically driven transmission expansion and to seek FERC approval of that methodology. The ISO also proposes to identify, and publish on its website, what it considers the preferred sites for new generation and transmission facilities.

In order for the ISO's ACAP proposal to become fully effective, a number of conditions must be met and institutional mechanisms created. First, before ACAP can be a fully effective tool, Pacific Gas & Electric Company (PG&E) and Southern California Edison Company (Edison) must be returned to creditworthy status and must be capable of procuring the necessary resources to satisfy the ACAP requirement. In addition, before the ISO can realistically expect LSEs to enter into forward contracts to supply ACAP, those LSEs subject to the California Public Utilities Commission's (CPUC) jurisdiction will likely require assurances that such forward contracts will be deemed reasonable by the CPUC and that the CPUC will allow recovery of the contract costs through retail rates. Therefore, the ISO believes that it will be unable to fully implement ACAP until the CPUC has concluded its ongoing proceeding regarding the specification of procurement rules for CPUC-jurisdictional entities. The CPUC has represented that it expects that the first phase of this proceeding will be concluded by October 2002. Finally, the ISO's ACAP proposal contemplates the development of certain information-driven requirements and mechanisms. For example, the ISO proposes to use an ISO Control Area forecast (broken down on a Local Reliability Area or LRA basis) to determine and allocate the ACAP requirement for each LSE in the LRA. The ISO proposes to base such determination on the historical loads of these entities. Currently, the ISO has actual load data for the UDCs, but does not have such information for LSEs. Therefore, as part of its proposal, the ISO proposes to develop and establish such a database.

These mechanisms will take time to develop, and will require close coordination with the UDCs, LSEs, and the affected state agencies and local regulatory authorities. Based on these considerations, the ISO anticipates that its ACAP proposal may not be fully implemented until these mechanisms are in place. Nevertheless, the ISO believes that it is imperative that the ISO, market participants, and all affected regulatory agencies move forward to establish the policy framework and institutions necessary to support the ACAP proposal. Subject to the constraints identified above, and elsewhere in this proposal, the ISO proposes to make the ACAP obligation fully effective by January 2004.

c. Details of ISO Proposal

The salient features of the ISO's ACAP proposal include:

1. **Load Serving Entity (LSE) Obligations** - A LSE's ACAP obligation would consist of three parts: the annual reporting of information to the ISO, the monthly certification that the LSE has procured sufficient resources to satisfy the ISO's forecast monthly load, plus a reserve margin (the Monthly Reserve Margin or MRM), and the daily obligation to schedule and commit sufficient resources in the ISO's day-ahead market to satisfy the next day's forecast load plus reserves, and to make available any additional resources deemed necessary to be available by the ISO (the Daily Reserve Margin or DRM).

2. **The Monthly ACAP Requirement** - The ISO's daily operating and regulating reserve level represent the desired level of operating system reliability. The operating reserve requirements are those of the WECC Minimum Operating Reliability Criteria (MORC). This daily reserve level (which may vary but must be specified for designing an ACAP obligation on a monthly basis) is sufficient in the day-ahead market. Without modification, however, it will not be sufficient for use as the month-ahead reserve level. This is because the load and plant outage forecasting error on a month-ahead basis is greater than the error on a day-ahead basis. Thus, the ISO will calculate the Monthly Reserve Margin based on a one day in ten year loss of load probability (LOLP). This will result in satisfaction of the ISO's daily operating requirements on a day-to-day basis. The ISO proposes that the MRM be calculated by summing historical ISO operating reserve and regulation requirements, a contingency for load forecast error, and a contingency for multiple outages and the variance of historical operating reserves related to forced outages. The contingencies for load forecast error and outages shall consider: (a) historical accuracy of ISO monthly load forecasts; (b) generating unit capability and types for every existing and proposed unit; (c) generator forced outage rates for existing mature generating units based on data submitted by the LSEs (or their ACAP generation suppliers) for their respective systems, from recent experience, and for new and proposed units based upon forecast rates related to unit types, capabilities and other pertinent characteristics; and (d) generator maintenance outage factors and planned outage schedules.

The ISO proposes to determine each LSE's ACAP requirement by first performing a monthly ISO Control Area-wide load forecast, applying the factor (1 + MRM), and then multiplying the total ACAP requirement by each LSE's contribution to the ISO's monthly system peak, based on the prior year's historical data. The ISO proposes to measure compliance with the monthly ACAP obligation by measuring an LSE's resources against its peak demand (the hours with a high probability of being the peak). An LSE must secure resources to cover their forecast load plus their Monthly Reserve Margin.

3. **The Locational ACAP Requirement** - The ISO proposes to define the ACAP obligation for the LSE in terms of Local Reliability Areas, which are the same as today's RMR areas. Thus, initially there will be eleven LRAs on the ISO Controlled Grid. The LRAs will reflect the critical subdivisions of the system that require individual designation of the resources to meet load and provide reserves. By defining the ACAP requirement in this fashion (locationally), the ISO is ensuring that sufficient resources will be available to meet the minimum resource requirements in each area. Thus, each month, each LSE serving Load within an LRA will have to procure its load-proportional share of the LRA's minimum resource requirements. The monthly certification must specify how much ACAP is associated with resources located in each LRA, the remainder of the ISO Control Area, and each external Control Area. The locational aspect of the ISO's ACAP proposal will not have material impact on LSEs (and their ACAP procurement requirements) until the ISO's existing RMR Requirements are phased out.[7] The ISO proposes to phase-out RMR over a multi-year period, until January 1, 2006. Until that time, the ISO proposes to continue to rely on RMR Generation to satisfy the ISO's locational requirements and would subtract from each LSEs ACAP Obligation their pro rate share (based on the load they serve in the LRA) of the RMR requirement.

   The CA ISO believes that this approach is consistent with the approach applied under the NY ISO UCAP requirement. Under the NY ISO tariff, the NY ISO establishes a capacity requirement for each transmission district. The NY ISO methodology establishes a "telescoping" requirement wherein minimum capacity requirements are established for each sub-area and the total requirement increases as each additional area is considered.

   Since the LRAs are primarily defined by transmission constraints, the ISO anticipates that, over time, the number of these areas will be reduced as a result of enhanced locational price signals and a proactive transmission planning and expansion process. However, with new generation coming online as the transmission system is being reinforced and expanded, there exists (and will inevitably continue to exist for some time) local generation pockets with limited export capability during specific periods. To ensure deliverability of ACAP resources, temporary limitations may be imposed on the total amount of ACAP that may be

[7] The ISO does not propose to phase out RMR Condition 2 units. Thus, RMR Condition 2 units would continue to be treated as they are today.

supplied from a local generation pocket to serve the ACAP requirements of LSEs outside the pocket (local area).

To ensure deliverability of ACAP provided from external control areas, nomination of ACAP imports must be backed by showing of adequate transmission reservation as needed in the other control areas (to the point of delivery to the ISO control area modeled in the ISO's network model), and an adequate level of transmission rights that enable scheduling over the tie point (e.g., ETC rights or FTRs from the tie point to some point within the ISO Control Area).

In the May 1 Filing, the Cal ISO had proposed to require that all LSEs obtain and utilize FTRs to deliver energy from their ACAP resources to the LRAs in which they served load. The Cal ISO no longer proposes such a requirement. After further consideration, the Cal ISO believes that as long as the Cal ISO's locational ACAP requirements are satisfied (i.e., a LSE satisfies its share of the Cal ISO's minimum generation requirements for a LRA), the Cal ISO's ACAP "deliverability" requirements are satisfied. Thus, as proposed herein, a LSE need not procure and utilize FTRs to satisfy any ACAP Obligation above and beyond its minimum locational ACAP Obligation. This is not to say, however, that LSEs cannot or should not utilize the FTRs they will be allocated (or procure) under the Cal ISO's FTR proposal to hedge congestion costs when arranging (self-scheduling) the delivery of energy from resources within their ACAP portfolio to serve their load. The Cal ISO recognizes that, ultimately, such business or risk management decisions are best left to the individual LSEs.

4. **The Daily ACAP Requirement** – With respect to the daily ACAP obligation, the ISO proposes to require that a LSE provide and schedule an amount of ACAP resources equal to its next-day's hourly load, plus reserves. As proposed, each LSE would have discretion as to what resources to schedule and/or self-commit on a daily basis in the ISO's day-ahead market. In addition, ACAP suppliers will also have to be available for commitment in the ISO's Residual Unit Commitment process to the extent that the ISO has identified a need for resources that is not satisfied by the self-scheduled and committed resources. While generally unlikely, such circumstances could exist if there is a significant change in the load forecast or because of transmission constraints on the system (i.e., the ISO must commit specific resources because of congestion).

5. **Consequences of ACAP Deficiency** - The ISO proposes that ACAP-deficient LSEs be required to: 1) provide to the ISO an amount of "Credible Demand Resources" necessary to cover their shortfall; and 2) based on the election described below, pay a deficiency charge. Each of these consequences is described below.

   Credible Demand Resources (CDRs) - If the ISO cannot meet all demand in real time, CDRs will be called and the deficient LSEs would be asked to curtail the identified amount of load. It is important to remember that these are demand resources and not bids. As such, demand resources are not price-based and will be utilized (i.e., the load will be curtailed) on a basis other than price. In the May 1 Filing the ISO proposed one flavor of demand resource. Basically, the ISO proposed that any deficient LSE must submit demand resources equal to their deficiency and that such resources would be called prior to the ISO declaring a Stage 1 Emergency (i.e., insufficient reserves). The ISO believes that this is a reasonable criterion in that had all LSEs procured sufficient ACAP resources, the ISO would not be reserve-deficient on a system basis. In addition, under this approach, deficient LSEs would be curtailed prior to curtailing any ACAP-sufficient LSE. The ISO continues to believe that this is a reasonable approach.

However, based on concerns raised regarding the ISO's imposition of penalties on state-regulated LSEs, the ISO, in this filing, is offering an alternative wherein a deficient LSE has the option to pay or not pay the monthly deficiency charge. To the extent that a LSE is ACAP-deficient on a month-ahead basis and elects to pay the monthly deficiency charge, the Credible Demand Resources required to be submitted by that LSE will not be curtailed until the ISO reaches a Stage 3 Emergency. However, if the LSE elects *not* to pay the deficiency charge, the LSE's Credible Demand Resources will be curtailed prior to a Stage 1 Emergency, consistent with the May 1 Filing. The ISO believes this is a credible approach because in either case the ISO's requirements are satisfied (i.e., capacity resources are identified in the forward market timeframe) and the LSEs have an incentive to take action to avoid curtailment (i.e., satisfy the day-ahead ACAP requirements and procure and schedule sufficient resources to satisfy load plus reserves).

A critical point that cannot be forgotten is the need to develop the mechanisms and arrangements necessary to effect selective load curtailment. As of today, the ISO, UDCs, LSEs and the affected regulatory authorities do not have the mechanisms or rules in place that permit selective curtailment of individual loads. While the ISO can currently call on certain dispatchable loads that participate in the ISO's markets, and the IOUs each have interruptible load programs in place in their individual Service Areas, these resources and programs are likely insufficient to meet the requirements (load volume) contemplated in the ACAP proposal. While the Cal ISO is committed to developing such mechanism and tools, this effort may take a few years and will require the concerted efforts and contributions of the California Public Utilities Commission, the California Energy Commission, other state agencies, as well as the IOUs, the UDCs and all other LSEs. Moreover, such an initiative will potentially require the development of new technologies; technologies the market must provide. Finally, in order to indoctrinate the market to the concept of using demand as a viable capacity resource, coarser, less selective measures may have to be developed and implemented during the transition period. For example, to the extent a LSE such as one of the IOUs proposes to rely on Credible Demand Resources as a substitute for ACAP, the ISO may have to establish processes whereby the ISO notifies the IOU (UDC) of possible curtailments in the day-ahead (e.g., the ISO submits a list of load to be curtailed to the UDC at the end of the day-ahead market) and the IOU/UDC makes whatever arrangements to curtail load the next day. While less elegant, such a process can achieve the intended result. In the end, the ISO strongly believes that the process for curtailment must be *transparent* and there must be *notification* well in advance of real time. The use of curtailable demand in such instances has significant public policy implications and must be done with the explicit coordination of state regulatory authorities and public policymakers.

Deficiency Charges – The ISO proposes that ACAP-deficient LSEs be potentially subject to both monthly and daily deficiency charges. The ISO proposes that the Monthly ACAP Deficiency Charge be weighted on a monthly or seasonal basis and chosen to reflect the probability of attaining peak for the month or season. The ISO proposes a monthly ACAP deficiency charge equal to $50/kw-month for summer months (June-August); $30/kw-month for shoulder months (March, May, September, October); $40/kw-month for winter months (December-February); and $20/kw-month for spring and fall months (April and November). The ACAP-deficient LSE will have two options:

1) Pay no deficiency charge and have its CDR curtailed when the Cal ISO declares a Stage 1 Emergency, or
2) Pay a penalty (deficiency charge), and have its CDR curtailed when ISO declares a Stage 3 Emergency (in which case the CDR will be curtailed before other rotating blackouts).

The penalty for failure to meet the daily ACAP obligation will be per unit of capacity and will be equal to 1/30th the monthly deficiency charge rate if the ISO (i.e., the system) is not short on daily ACAP, and will be a higher level (1/3 of the monthly deficiency charge rate) if the ISO experiences a shortage of daily ACAP. The ACAP deficient LSE must nominate adequate Credible Demand Resource to be curtailed in case of Reserve deficiency. The daily deficiency charge will be waived to the extent that the deficient LSE elects to have the Demand Resource curtailed prior to a Stage 1 Emergency. The deficient LSE may elect the option of having the Demand Resource curtailed only under Stage 3 Emergency only if it pays the daily deficiency charge and 1) it was ACAP sufficient in the month ahead, or 2) had paid monthly deficiency charge and identified adequate Demand Resources in the month ahead to be curtailed under Stage 3 Emergency conditions.

Although not specifically addressed in the May 1 Filing, the ISO now proposes that deficiency charge revenues be allocated to LSEs that are ACAP-sufficient. Such allocation will be limited to the extent of the LSE's designated monthly or daily ACAP resources participate (i.e., schedule or bid at prices consistent with the prevailing bid caps), in the market. The ISO believes that this approach is comparable to that in place in the Eastern ISO's that have capacity obligations and also provides an additional incentive to LSEs to satisfy their ACAP Obligation.

6. **ACAP Interconnection Requirements** - The ISO intends to develop and implement new interconnection requirements for generation that is proposed to be a certified ACAP resource. These requirements are likely to require that a resource's full or ACAP-certified output be "deliverable" to load. That is, if the developer of a potential ACAP resource contracts with an LSE for the delivery of 1000 MWs, that resource will be required to pay for/construct interconnection facilities and potentially

transmission upgrades necessary to ensure the delivery of all 1000 MW. Obviously, the development of that policy will have to be consistent with the interconnection policies and processes ultimately adopted as a result of the Commission's Notice of Proposed Rulemaking on Standardized Generator Interconnection Procedures and Agreements.

7. **Monitoring of the ACAP Market** – As provided in the May 1 Filing, the ISO is proposing that all LSEs must report, on a monthly basis, their costs incurred in satisfying the ACAP obligation. The ISO will file monthly reports to FERC on the status and functioning of the ACAP market. In addition, the ISO will require the WECC participating members within the ISO Control Area to submit certain information (load forecasts, information on demand programs, and resource and transmission information) to the ISO on a periodic basis so that the ISO can fulfill its responsibility to submit such information to the WECC to satisfy the requirements of the WECC's annual five-year resource assessment process.

d. Alternatives to ACAP

The ISO's ACAP proposal has been the subject of much debate by Market Participants engaged in the ISO's MD02 proposal. As reflected in the comments filed at the Commission in response to the May 1 Filing, there are many divergent views of the proposal. A number of parties, while not necessarily supporting the specifics of the ISO's ACAP proposal, believe that some form of capacity requirement is necessary. Others argue that no mechanism to ensure long-term supply adequacy is necessary and that California is only experiencing a short-term supply problem. Of those in favor of explicit measures to support long-term supply adequacy, there are those that contend that the ACAP proposal inappropriately extends the ISO's (and the Commission's) jurisdiction over the procurement practices of LSEs and argue that such matters are best addressed by local regulatory authorities. Others contend that the Commission should move quickly to establish a capacity requirement in California.

It is not surprising that such divergent views exist. The Commission itself has raised this issue to a national level in its Standard Market Design Rulemaking proceeding. The debate can in part be captured by summarizing and evaluating two proposals that, in the ISO's opinion, define the end points of the capacity requirement continuum. Not surprisingly, once again in the ISO's opinion, the ACAP proposal falls somewhere in the middle.

e. Alternative Proposal – Advisory Forward Energy Commitment

Early in the MD02 developmental process, California state agencies engaged in the MD02 process formed the California Interagency Working Group (CIWG). The CIWG was formed to develop a consensus position among the state agencies on the ISO's MD02 proposal. To a large extent that effort appears to have been successful. In response to the ISO's proposed ACAP proposal the CIWG developed what it thought was a more measured and appropriate proposal entitled the Advisory Forward Energy Commitment (AFEC) proposal.[8]

As provided in the AFEC proposal, the AFEC is built upon three foundational principles (AFEC at 2):

1) It is mandatory for load to forecast accurately and schedule accurately;

2) It is mandatory for supply resources to schedule accurately and perform according to schedules and accepted bids; and

3) It is essential for the ISO to know ahead of real-time operation the quantity and location of resources expected to meet load.

Thus, the ISO believes that the AFEC and ACAP proposals share certain critical objectives: 1) ensure that LSEs procure, in a forward-market timeframe, an amount of resources sufficient to meet their demand plus reserves; and 2) the ISO should have advance knowledge of resources (quantity and location) required to meet demand and the commitment of those resources. In summary, the ISO believes that the ISO and CIWG are in agreement that LSEs, and not the ISO, should be responsible for procuring the resources necessary to reliably serve load and that the ISO's real-time activity should be minimized to the greatest extent possible in order to support reliable system operation.

In order to achieve the above-stated objectives, the CIWG's AFEC proposal recommends the following framework as the basis for a going-forward capacity sufficiency review process (AFEC at 2-3):

- The ISO, LSEs and Local Regulatory Authorities (LRAS) interact to determine the desired level of supply needed to reliably operate the grid (The AFEC process would research and publish advisory non-binding estimates on the level of energy and reserves necessary to reliably operate the grid in real time);

- Parties would work together to develop accurate supply and demand forecasts, including estimates of Ancillary Service requirements (the AFEC proposal states that these could be done on a sub-utility level to address regional reliability and transmission constraints);

- Parties would apprise the ISO with relative certainty of the upcoming resource situation sufficiently in advance of actual operation;

- Allow the procurement processes overseen by the LRAS to be effectively integrated with reliable operation of the grid (LRAS would commit to ensuring that they will develop resource procurement processes and mechanisms for LSEs

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[8] The AFEC proposal was appended to the State of California Electricity Oversight Board's May 7, 2002, comments in response to the Commission's Options Paper issued on April 10, 2002, in Docket No. RM01-12-000.

under their jurisdiction that will require resources to match accurate load forecasts);

- Allow development of mutually-agreed upon guidelines for tabulating energy and capacity available from various categories of resources;

- The AFEC process would develop reporting processes and timelines by which all LSEs would report to the ISO their own level of energy and reserve procurement. The AFEC proposal provides that this could be done on a month-ahead basis with week-ahead and day-ahead updates. The AFEC proposal provides that these reports from LSEs are mandatory. However, the AFEC proposal also provides that, as a result of reviewing these reports, the ISO would take no action to remedy any deficiency other than to notify the LSE of their deficiency (relative to the previously discussed benchmarks) and the potential consequences to their load, including the potential for increased costs and greater probability of rotating outages; and

- Each generator with a Participating Generator Agreement (PGA) is required to file a comparable (to LSEs) Month Ahead and Week Ahead report that describes the portions of its capacity that are encumbered by commitments and the portion that is available. The AFEC proposal provides that these reports are mandatory and should be linked to the reports submitted by LSEs.

The ISO is generally supportive of the data-collection/processing and information-sharing processes outlined above and envisioned by the CIWG to form the foundation of the AFEC process. While it is difficult to assess without knowing the specific details of the AFEC process (the CIWG states that such details would be developed in a collaborative process to come), the ISO believes that the AFEC process is largely compatible with, and conceptually similar to, the ISO's proposed ACAP process.

So, where do the AFEC and ACAP proposal diverge? Principally, the ISO believes that the two proposals diverge on the issue of the ISO's role in (and oversight of) the process and the need for explicit measures to ensure that LSEs procure, in the forward market, the resources necessary to reliably serve load. In the Cal ISO's opinion, the essence of the difference is captured in the words used to describe the two proposals – the CIWG's proposal is "advisory", whereas the Cal ISO proposes to establish a firm "obligation" On LSEs. The AFEC process relies on the LRAS to establish clear and enforceable rules to ensure that LSEs procure sufficient resources in the forward-market. In contrast, the ACAP proposal would impose penalties, imposed by the ISO under the ISO Tariff, on LSEs that are capacity-deficient. As noted above, the ISO believes that such deficiency charges are a necessary incentive to LSEs to comply with the capacity obligation.

More importantly, while in the long-term the CPUC and other LRAS may establish procurement rules for LSEs, no rules for LSE procurement currently exist in the California market. Thus, left unchallenged, LSEs could continue to inappropriately rely on spot market purchases facilitated by the ISO, a practice that impairs reliable system operation and does nothing to address the supply-demand imbalance. At present, the CPUC contemplates specifying the procurement rules for the state's investor-owned utilities (IOUs) for 2003 by October of this year. The CPUC has not determined when it will determine procurement rules for the IOUs beyond 2003. Therefore, the ISO believes it prudent to proceed and establish a capacity requirement now. To the extent that the CPUC and other LRAS establish procurement rules for LSEs, the ISO and other parties can reexamine the need for, and details of, the ACAP proposal. In fact, the ISO's proposed tariff language specifically provides for a periodic review of the ACAP Obligation by the ISO.

f. Alternative Proposal – Reliant Proposal

On April 30, 2002, Reliant Energy Power Generation, Inc (Reliant) filed a "Motion for Establishment of a Capacity Market in California with Associated Must Offer Obligations and Price Mitigation Measures." Among other things, Reliant called for the Commission to establish: 1) an interim monthly ACAP market that would begin in October 2002 and end in December 2004; and 2) a forward capacity market ("Regional Reliability Commitment" or "RRC") with delivery beginning in January 1, 2005. Reliant stated that these markets, "are mechanisms for ensuring that adequate capacity reserves are available to meet loads in future years by providing the missing price signals needed for new generation." (Reliant at 2). Reliant stated that its proposal is "designed specifically to meet the following needs of the California market" (Reliant at 2) including, among others, assurance that the ISO has sufficient capacity available to serve peak load on a month-to-month and long-term basis and assurance that there are long-term price signals for generation capacity that will encourage new generation development. (Reliant at 2).

Reliant's Interim ACAP proposal and its long-term RRC proposal both contemplate the ISO facilitating formal capacity markets. The Interim ACAP proposal provides LSEs with the option of either self-arranging their capacity or allowing the ISO to acquire capacity. The ISO would establish the monthly requirement (forecast peak load plus reserves), each LSE would certify the amount of self-arranged capacity it will provide, then the ISO would compare its forecast needs against the amount of self-arranged capacity and procure any net short amount. To procure the net short amount, the ISO would conduct a single clearing price auction in which both generation and load could bid. The cost of procurement would be allocated to LSEs based on actual peak demand in proportion to their net short position. (Reliant at 10). Significantly, Reliant proposes that all suppliers in the ISO market (i.e., those with a PGA) be obligated to offer all available and otherwise uncommitted capacity in the ACAP auction. In addition, Reliant proposes that generators selected as ACAP resources have the obligation to bid into the ISO's day-ahead markets and bidding any remaining energy in real time. Reliant also proposes that ACAP resources be required to submit a "Capacity Compliance Report" in which they certify the availability of each resource on a monthly basis. ACAP suppliers will thus verify that they bid into the ISO's day-ahead energy or ancillary services markets. (Reliant at 10-11 and 13-14).

Reliant's proposed RRC mechanism is structured in a manner similar to its Interim ACAP proposal. The RRC provides LSEs two options, they can self-arrange their capacity or purchase it from the ISO through a single clearing price auction. (Reliant at 16). As opposed to the Interim ACAP proposal, the RRC provides for annual capacity auctions for ISO-determined requirements three-years out. Reliant states that the three-year forward load forecast shall be increased by a reserve margin to be determined by the ISO. (Reliant at 16). Reliant also proposes that the ISO establish, as part of the auction, a maximum energy payment amount that will establish the maximum permissible bid from resources selected in the auction. In addition, similar to the Interim ACAP proposal, Reliant proposes that generators with a PGA be required to offer all available capacity in the annual RRC auction. (Reliant at 17).

As stated above, the objectives of the Reliant proposal are once again well aligned with those of the ISO's ACAP proposal – ensuring adequate capacity and a foundation for new generation investment and development. While not speaking to the merits of the Reliant proposal in general, it is clear that the Reliant, CIWG and ISO proposals all share some common objectives. Moreover, the ISO believes that certain aspects of the Reliant proposals warrant careful consideration, including the "must-offer" provisions and the compliance certification procedure. It is obvious, however, that the Reliant proposal would place the ISO in a central procurement role – a role that the ISO is not entirely comfortable with nor which it thinks is necessary.

The AFEC, Reliant and ISO proposals all have a common goal, that of ensuring stable grid operations. The AFEC proposal attempts to achieve that goal by establishing a process for validating the availability of resources necessary to reliably serve load and relying on close oversight and scrutiny of LSE procurement practices by LRAS. The Reliant proposal attempts to achieve this objective by placing the ISO in a central procurement role in which it can directly procure all capacity necessary to ensure reliable operations and assign any costs of that procurement to LSEs. The ISO's ACAP proposal lies somewhere in between. In the end, the ISO believes that its ACAP proposal, as proposed herein, strikes an appropriate balance between the two approaches proposed by Reliant and CIWG. The ISO believes that the ACAP proposal appropriately blends the ISO's reliability requirements and LSE self-discretion on procurement and scheduling/commitment decisions into an incentive-compatible mechanism that supports reliable system operation and investment in the California market.

7. Market Power Mitigation

a. Locational Market Power

Under the LMP congestion management approach, bid mitigation provisions for locational market power must be available in the forward markets as well as in real time. The reason for this is that there will rarely if ever be enough unaffiliated suppliers in a local area of the grid to provide a competitive supply of energy bids to relieve a local transmission constraint. While LMP does mitigate the ability of suppliers to play the well-known "Dec Game" that has plagued the ISO at various times, it does not prevent the exercise of local market power when a specific level of local generation is needed to maintain local reliability. The ISO has therefore designed its proposal for forward bid mitigation for locational market power to be consistent with the Commission-approved procedures used in other ISOs that use a LMP-based congestion management approach.

b. Damage Control Bid Cap

The ISO does not propose any change for the comprehensive design from what was proposed in the May 1 Filing for October 1, 2002 implementation.

c. Automatic Mitigation Procedure (AMP)

Once the ISO begins to operate the integrated forward markets in Phase 2, the AMP will be applied to the Day Ahead and Hour Ahead Energy Markets and the Hour Ahead Residual Unit Commitment process, as well as to the Day Ahead Residual Unit Commitment process and the Real Time Energy market during the pre-dispatch period, as stipulated in the May 1 Filing. Reference energy bid levels for any given resource will be the same in all of these markets, and will be calculated based on the resource's accepted bids in all of these markets.

d. 12-Month Market Competitiveness Index (12MMCI)

As described in the May 1 Filing, the 12MMCI is an indicator that compares a 12-month rolling average index of the actual hourly cost of energy (the Actual Average Market Cost or AAMC) against a corresponding 12-month rolling average index of the estimated cost of energy under competitive market conditions (the Hourly Competitive Baseline Cost or HCBC). Effective October 1, 2002, if approved by the Commission, these indices will be based on prices and supply resources in the ISO's real time market as well as short-term contract prices and quantities provided by the California Energy Resource Scheduler (CERS), the state agency that is currently authorized to procure energy on behalf of the consumers served by California's investor owned utilities. Once the ISO begins to operate the integrated forward markets in Phase 2, the 12MMCI will utilize an AAMC that is calculated as the quantity-weighted average of the ISO Day Ahead, Hour Ahead and Real Time Energy prices. Similarly, the HCBC will be based on the total quantities of energy that cleared in all three ISO Energy markets for each hour.

8. Performance Obligations

a. Penalties for Excessive Uninstructed Deviations

The ISO does not propose any change for the comprehensive design from what was proposed in the May 1 Filing for October 1, 2002 implementation.

b. Making Performance Obligations Explicit

At the May 21, 2002 meeting of the ISO Board of Governors, in the context of the MD02 discussion, the Board directed ISO staff to meet with members of the State of

California's Inter-agency Working Group (CIWG) to consider a CIWG proposal to add provisions to the ISO Tariff to make explicit the obligation for market participants to submit forward schedules that accurately reflect their anticipated real-time loads and generation levels, and to follow these schedules and ISO dispatch instructions in real time. Subsequently ISO staff met with the CIWG to discuss the issue, and in the process identified certain aspects of the CIWG proposal that are fully consistent with both the objectives and the specifics of the MD02 design. As a result the ISO is proposing revisions to Tariff Sections 2.3.1.1 and 2.3.1.2. These revisions make it explicit that final hour ahead Energy and Ancillary Services schedules, Supplemental Energy Bids, and day-ahead unit commitment decisions are all binding obligations on the part of supply resources. The ISO believes that these proposed Tariff revisions do not create requirements or obligations on market participants that are not already present either in the ISO Tariff as it reads today or in the elements of the MD02 proposal. At this time the ISO is not proposing any additional enforcement mechanisms related to the stated obligations, beyond the uninstructed deviation penalties that have already been filed as part of the May 1 Filing.

In order to ensure that market participants would be fully aware of the ISO's meeting with the CIWG in response to the Board's May 21 direction, and would have an opportunity to review and comment on the proposed changes to Sections 2.3.1.1 and 2.3.1.2, the ISO issued a Market Notice on June 5 informing stakeholders of the meeting, directing them to the posted draft tariff language, and requesting comments by the afternoon of June 7. Comments were received from seven parties and may be summarized as follows. The ISO response follows each comment.

1. Change in Obligations – The proposed tariff changes create new or more stringent obligations on suppliers.

ISO Response – The ISO believes that these proposed Tariff revisions do not create requirements or obligations on market participants that are not already present either in the ISO Tariff as it reads today or in the elements of the MD02 proposal. Since start-up of ISO operations the Tariff has provided that bids for Imbalance Energy not withdrawn by the bidder by 45 minutes prior to the start of the operating hour ("T-45") are binding commitments by the bidder to provide Energy when dispatched by the ISO.[9] The design of the uninstructed deviation penalties discussed above is based on this view and implicitly extends the binding commitment to the final hour ahead schedules of supply resources. The logic behind this extension is the need for ISO operators to have accurate and dependable expectations regarding the real-time performance of supply resources, in order to ensure the reliable operation of the ISO Control Area. Because final hour ahead schedules are the reference for ISO dispatch instructions, uninstructed deviations from these schedules are just as problematic for reliable real-time operation as deviations from dispatch instructions.

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[9] See Tariff Section 2.5.22.4.1. "Supplemental Energy bids cannot be withdrawn after forty-five (45) minutes prior to the Settlement Period... The ISO may dispatch the associated resource at any time during the Settlement Period."

Similarly, the ISO must be able to depend on the commitment decisions made in the day ahead time frame – both the self-commitment of resources in the context of the day ahead market and the ISO's commitment of resources in the RUC process. In particular, the RUC process assumes that resources self-committed in the day ahead market will indeed be operating in real time. If any of these self-committed or RUC-committed resources are arbitrarily de-committed by their operators after the day ahead time frame, it will likely render the ISO's RUC procurement insufficient and undermine the ISO's efforts to ensure that adequate supply resources will be available for real time operation.

It is no exaggeration to state that a primary goal of the MD02 project has been to achieve greater certainty for ISO operators regarding the real-time availability and performance of the resources needed to serve load and provide reserves. This goal bears directly on a core function of the ISO, and therefore design objectives 4, 7 and 12 in Section 3.5 of the May 1 Comprehensive Design Proposal address this goal.

2. Definitions – The ISO should precisely define certain terms in the new provisions (e.g., "operating orders"), and should specify more precisely when the obligations do and do not apply, and what the consequences are when a supplier does not comply.

ISO Response – The term "operating orders," while not a defined term, appears in the tariff section on System Operations (Section 2.3) to encompass all orders and instructions the ISO may issue to accomplish its core function of reliable operation. The obligations apply at all times. As noted above, the ISO is not specifying at this time any new enforcement actions related to this provision.

3. Process – Prior to release of the draft tariff language the ISO should have held discussions with all stakeholders, not just the CIWG, and more time should be allowed for stakeholder comment on the draft.

ISO Response – In committing to the present filing date for the comprehensive MD02 tariff language, the ISO made it clear that there would be no opportunity for advance stakeholder review of the filing. Rather, the ISO would conduct stakeholder meetings after the filing was submitted to the Commission.[10] The ISO made an exception for this particular tariff section because of the unique circumstance in which the Board had directed ISO staff to work with the CIWG to resolve this issue.

4. Changes after the Day Ahead Market – The day-ahead unit commitment element of the proposal overly restricts the ability of suppliers to make schedule changes after the day ahead market.

ISO Response – Some parties misunderstood the proposal to apply to scheduled operating levels established in the day ahead. This is not correct. The intent regarding day ahead is only to ensure that resources that were committed to be on-line for the

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10 See May 1, 2002 MD02 Transmittal Letter, page 5.

next day will indeed be on-line. The phrase "as approved by the ISO" was inserted into the day ahead paragraph specifically to allow resources to be de-committed when the ISO can determine that they are not needed or acceptable substitutes are available.

5. Asymmetric Treatment – The proposal places obligations on suppliers but not on loads.

ISO Response – Because MD02 is a comprehensive design proposal, symmetry is achieved through the totality of the provisions, not in each provision independently. The corresponding obligation on loads is embodied in the ACAP Obligation.

6. Compensation for Unit Commitment – The ISO should pay suppliers a negotiated price not to de-commit a day-ahead self-committed resource.

ISO Response – The proposed provision does not place any limitations on suppliers that merit additional compensation. As noted above, the presumption of the RUC process is that resources committed day ahead will actually be available in real time. If a supplier wishes to de-commit a resource after day ahead, it may do so with ISO approval. Arbitrary reversal of a day-ahead commitment decision, particularly of a long-start-time unit, is too disruptive of real-time operation to be an allowable dimension of decentralized market decision-making.

7. Mid-hour Dispatch Instructions – If an importer is prevented from complying with a mid-hour dispatch instruction due to an action of another control area operator, this should be deemed a condition "beyond the control of the resource owner" for the purposes of this tariff provision.

ISO Response – The ISO agrees that this situation would be deemed beyond the control of the resource owner.

8. Unscheduled Flow (USF) – Under a USF condition, an ISO dispatch instruction could be in conflict with WECC reliability requirements, and therefore the supplier would not be able to comply with the dispatch of its supplemental energy bid.

ISO Response – Although this situation is theoretically possible, in practice the ISO will be fully aware of a USF condition and would not issue a dispatch instruction that was in conflict with reliable operation of the grid.

B. INTERIM PROVISIONS TO SUPPORT PHASING OF IMPLEMENTATION

As the ISO has previously explained, full implementation of the Comprehensive Design Proposal is constrained by the lead times needed for development, testing and integration of the Full Network Model and the full effectiveness of the ACAP Obligation. The ISO can, however, implement certain major features of the design earlier and thereby achieve many of the benefits of the MD02 design, even without the FNM and the ACAP. Toward this end the ISO has prepared an interim tariff section that specifies modifications to the comprehensive design tariff that are required during the period when the FNM is not available. (Thankfully an additional tariff section to capture interim tariff modifications in the absence of ACAP is not needed. In areas of the comprehensive design tariff where the availability requirements of ACAP resources apply, the ISO has utilized the generic term "capacity resource" to refer to any resource that is subject to availability requirements, either under a must offer obligation or in connection with ACAP.) Once the FNM is ready for implementation, the interim tariff section can be withdrawn and the appropriate comprehensive design tariff language will apply.

During the first quarter of 2003, the ISO anticipates having the necessary software ready to support the changes associated with the integrated day-ahead market. These changes will replace the separate congestion management and ancillary services markets with a simultaneous energy, congestion, ancillary service and unit commitment market. The Market Separation Rule and the balanced schedule requirement will be eliminated so that SCs may submit unbalanced supply and demand bids. Energy bids associated with forward schedules will serve both for energy trading and for congestion adjustments, so there will be no need for distinct Adjustment Bids. This much is consistent with the comprehensive design tariff language and requires no special interim provisions. The lack of the FNM, however, will require the Phase 2 implementation to use the existing three-zone network model, and to preserve the current distinction between inter-zonal and intra-zonal congestion. In addition, the current method of evaluating losses using Generator Meter Multipliers (GMMs) will be retained, since the FNM and the AC-OPF are required to integrate loss calculations into both the forward market and the real-time dispatch. The tariff changes contained in the interim section (Tariff Section 32) primarily capture those elements of the existing tariff language that must be retained due to continued use of the three-zone model and the separate and distinct management of inter-zonal and intra-zonal congestion.

As already noted, the current distinction between inter-zonal and intra-zonal congestion will still exist during Phase 2. The ISO proposes to manage intra-zonal congestion through the end of Phase 2 by calculating, publishing and enforcing forward scheduling limits on generators within congested areas of the grid, to prevent the establishment of infeasible forward schedules in these areas. In the context of recent meetings sponsored by the Commission, the ISO has been working with stakeholders to develop an approach that will take into account market-based bids with appropriate market power mitigation measures. The result of this effort is not included in the present filing, however, and will be filed in the near future.

Because the real-time SCED will also use the FNM and AC-OPF, the ISO proposes to implement the real-time economic dispatch procedures using the current three-zone network model. Interim Tariff Section 32 therefore also captures those elements of the existing tariff language that must be retained in relation to real-time dispatch, pricing and settlement based on the three-zone network model.

III. REQUESTED ACTIONS AND EFFECTIVE DATE

Accordingly, the ISO respectfully requests that the Commission:

(1) Accept the changes to the ISO Markets reflected in the blacklines in Attachment A effective the later of May 1, 2003 or when the ISO announces it is ready to implement the MD02 long term elements.

(2) Accept the changes to Section 9 of the ISO Tariff regarding FTRs effective the later of October 1, 2003 or when the ISO announces it is ready to implement the full network model with the exception of the proposed changes to Sections 9.4.1 and 9.4.2 which will should be accepted effective January 1, 2003.

(3) Accept changes to implement the ACAP obligation effective January 1, 2004.

IV. SERVICE

The ISO has served this filing on the Public Utilities Commission of the State of California, the California Energy Commission, the California Electricity Oversight Board, and all parties with effective Scheduling Coordinator Service Agreements under the ISO tariff. In addition, the ISO has served all parties in Docket No. **Docket No. ER02-1656-000** and has posted a copy of the filing on its Home Page.

V. NOTICES

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

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VI. SUPPORTING DOCUMENTS

The following documents, in addition to this letter, support this filing

Attachment A - Blackline of changes to implement comprehensive market redesign (other than FTRs and ACAP);

Attachment B	-	Blackline of changes to Sections 9.4.1 and 9.4.2 to enable the ISO to sell FTRs for durations of less than one year;
Attachment C	-	Blackline of the remaining changes to implement revised FTR Program;
Attachment D	-	Blackline of changes to implement ACAP program;
Attachment E	-	Summary Table of ISO Market design changes other than FTRs and ACAP
Attachment F	-	Summary Table of changes to FTR provisions;
Attachment G	-	Summary Table of changes to incorporate ACAP;
Attachment H	-	Advisory Forward Energy Curtailment proposal;
Attachment I	-	Reliant Companies' Motion for the Establishment of a Capacity Market; and
Attachment J	-	Notice of filing

Respectfully submitted,

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