Attachment D

SUMMARY OF COMMENTS ON OUT-OF-MARKET PROPOSAL

Party	Comments
SoCal Edison	The proposal should be rejected in its entirety. 1) The administrative costs of the OOM payment option are not warranted given the recent increase in the price caps and other currently available alternatives for generators to protect themselves. • SCE understands that whether a generator bids into the market or accepts the "calculated price" proposed in the Tariff language, it would still be subject to the cap. A generator could protect itself simply by bidding the unit into the market at a price that would cover their start-up costs. • The proposed Tariff language goes well beyond the recovery of start-up costs. Recovery of daily gas imbalance charges and the energy and capacity payments are inappropriate. Capacity charges are not intended to benefit those who remove resources from the market due to their own economic concerns. Imbalance gas costs are also implicitly included in the energy payment. 2) The proposed "calculated price" payment is substantially greater than the variable costs of operating a unit and is likely to encourage withholding. This is especially true because separate payment components for capacity and energy may result in double payment for capacity. This is similar to the RMR "A Agreements" which the MSC and DMA identified as responsible for substantial withholding during summer 1998. 3) The proposal would provide what are essentially RMR payments to units not designated as RMR by the ISO. This could lead to potentially greater payments to existing RMR Units because the RMR settlements allow RMR owners to negotiate changes in the RMR Contracts or file for changes under § 205 of the FPA if the ISO enters into or operates under a Non-Conforming RMR Contract. SCE believes the proposed use of OOM payments for locational requirements would satisfy this requirement. 4) PTOs should not be allocated costs for OOM calls due to Intra-Zonal Congestion or other location-specific needs. Such allocation is inappropriate. Sections 7.2.6.3 and 7.3.2 of the Tariff require that Intra-Zonal Congestion costs be allocated to Load in the Zone where the congestion occurs. Allocation of Intra-Zonal Congestion costs to PTOs also sends incorrect pricing signals by intercepting Intra-Zonal Congestion Cost signals that should go to market participants, The proper signals can result in the creation of a new Zone where such costs become "significant." Lastly, PTOs cannot control capacity reductions due to Acts of God, other control areas, or the tripping of generation - in approving the TO Debit solution in approved Amendment 13, FERC recognized that PTOs should not be responsible for any costs resulting from such reductions. The OOM proposal would make PTOs responsible for similar costs.
SMUD	Opposes the proposed revisions to Section 11.2.4.2 which would permit the ISO to dispatch generation not bid into the A/S or adjustment bid markets for reasons other than averting or responding to an emergency. Argues that this approach is unacceptable and inconsistent with the provisions of "Section 5.3" of the Tariff (possibly referring to Section 5.1.3), which were carefully crafted among previous control area operators, municipal utilities, and ISO attorneys early in the Governing Board's existence in order to allow municipal utilities to honor their responsibilities for resource operation and Load-serving

	obligations. States that the ISO's failure to respect this resolution also underlies the MSS dispute and many of SMUD's unresolved issues.
Enron (Carl Imparato)	Offers an alternative Intra-Zonal Congestion Management (AZCM) proposal as a "less onerous" alternative to the OOM proposal. Argues that a new mechanism for AZCM is necessary because: 1) the ISO currently relies on non-market RMR generation for AZCM; 2) FERC's rejection of the NewGen Policy was due solely to the current AZCM approach; and 3) the acceptance of portfolio bidding by the DMA is dependent upon development of an acceptable AZCM policy. Proposes a framework for AZCM which is intended to address the locational market power of some units. Under this framework, intra-zonal dispatch resulting from the ISO's acceptance of Adjustment Bids or Supplemental Energy Bids would be paid: • the higher of the SC's incremental energy bid price or the zonal balancing energy price for the interval for incremental energy; or • the lower of the SC's decremental energy bid price or the zonal balancing energy price for the interval for decremental energy. The proposal would permit the ISO, upon approval of the ISO Board and FERC, to substitute "Demonstrable Cost"-based price caps or floors for SCs' incremental or decremental bid prices, when such bids are used for the purpose of AZCM and are necessary to mitigate the exercise of local market power by SCs. Under the proposal, redispatch service acquired under the mandatory redispatch authority of the ISO would be paid: • the higher of the SC's Demonstrable Cost or the zonal balancing energy price for the interval for incremental energy supplied to the ISO; or • the lower of the SC's Demonstrable Cost or the zonal balancing energy price for the interval for decremental energy supplied by the ISO. The proposal includes a discussion of what could be included as "Demonstrable Costs," including variable production costs and the costs of foregone opportunities.
Williams Energy Marketing & Trading Co	Opposes the aspect of the proposal which would permit the ISO to dispatch units that have bid into the Imbalance Energy market or submitted an Adjustment Bid and to then pay those units one of the OOM market alternatives, neither of which is based on valid bids submitted to the ISO. The ISO should be required to pay the owner the bid price for the service. Anything else is an attempt by the ISO to obtain RMR service without paying the costs of an RMR Contract. By eliminating most of the RMR Units in the LA Basin for 2000, the ISO has implicitly recognized that market bids should be available to solve system emergencies or locational needs. Williams contends that all market bids should be exhausted prior to use of any RMR Units or forcing units without market bids to dispatch. Expresses two concerns about the proposed alternative payment formula in Section 11.2.4.2 (b)(ii): • the average energy payment proposed by the ISO might result in a unit operating at a loss, which an owner should not be required to do: and • the formula ignores certain costs incurred by the owner, including variable O&M charges, fixed startup costs, emissions fees, and lost market opportunity costs. Proposes an alternative approach whereby the ISO would annually solicit bids from the owners of each unit. These price set forth in these bids would be paid if the owner has not participated in any market and the ISO is required to dispatch that unit due to a system emergency. Suggests that this approach avoids the pitfalls of the ISO's proposal and provides the ISO with a "market alternative."

Reliant Energy	Reliant strongly objects to the ISO's proposal to rely on OOM calls for Intra-Zonal Congestion Management and other uses. Recommends that the ISO not proceed with a Tariff filing but instead initiate a stakeholder process to consider the issues related to use of and pricing for OOM calls. Believes that the alternative payment option proposed by the ISO would be fair as applied to OOM calls under the ISO's current policy of making such calls in the event of a system emergency or where such an emergency is threatened. Contends that linking of OOM pricing to the ISO's Intra-Zonal Congestion Management policy has not been adequately presented to stakeholders.
PG&E	PG&E opposes the proposed allocation of OOM call costs to TOs when a call is necessary due to a transmission outage or a location-specific requirement. This proposal would be an unjustified change in existing, rational and long-standing allocation methods. • "Location-specific requirements" are simply a form of Intra-Zonal Congestion and transmission outages can result in Intra-Zonal Congestion. The ISO's market design and the Tariff currently require that Intra-Zonal Congestion costs be allocated to the market within that Zone. This allocation should not change just because there is not workable competition and/or the ISO needs to purchase energy out-of-market • Allocating the costs of OOM calls to TOs directly contradicts the ISO's rationale for the TO Debit solution in Amendment 13. There, the ISO recognized that congestion costs resulting from a line deration after the close of the Hour-Ahead Market were market costs which could be resolved using Adjustment Bids. • Also notes that the ISO's proposal permits it to satisfy a locational requirement by dispatching a resource "out-of-sequence." If the resource was dispatched according to its bid, the market would pay the costs of the energy meeting the demand at this location - there is no reason that the costs should be allocated differently simply because the ISO dispatches the resource under alternative procedures or with an alternative payment option. • If allocation of OOM costs to TOs is intended to provide TOs with incentives to maintain their systems, such incentives already exist in the Transmission Control Agreement. PG&E offers comments and requests additional information on or clarification of other aspects of the ISO's proposal. • Suggests reformatting 11.2.4.2(b) to make it easier to follow. • Requests confirmation that "daily gas imbalance charges" refers to costs associated operational flow orders (OFOs) or emergency flow orders (EFOs) as defined in gas transmission tariffs of gas distribution utilities and other gas transmission tariffs. • Recommends that ISO OOM calls be logged and published on PMI to make it clear to the market why the resource was called. • Requests the rationale for replacing the definition and practice for out-of-sequence calls in Section 11.2.4.2 and asks how a resource that has submitted a bid can be called "out-of-market." • Requests the background and analysis that resulted in the proposed definition of the "calculated price." Seeks information on the range of prices that would be expected if the formula were adopted. • Specifically requests an estimate of how much money PG&E as a TO might be expected to be charged under the ISO's proposal, based on operational baseline data for the past 12 months. • Asks about the steps the ISO would take to determine whether an SC or generator has applied best efforts to eliminate or reduce a daily gas imbalance charge.

Camden L. Collins	The preamble of 11.2.4.2 should either be identical to the causation language ("such dispatch may result from, among other things . . .") from 11.2.4.2.1 or the overlap should be eliminated. Also, the phrase "among other things" may concern some parties. The proposal could be seen as an attempt to circumvent RMR settlement terms. The preamble of 11.2.4.2 refers to dispatch in "circumstances where an RMR Unit would be used to resolve Intra-Zonal Congestion and there are no such RMR Units available . . . ." Because there are many possible causes for dispatch under this section, RMR owners may wonder whether the settlement terms will be honored if their units are dispatched for some reason other Intra-Zonal Congestion. Also, the reference in 11.2.4.2.1 to "location-specific requirements" comes close to the settlement terms about what constitutes adequate locational resources. Notes that some parties have expressed concern that the ISO would use the OOM Tariff language to reduce costs rather than call on their higher cost bids.
Southern Company Energy Marketing	The proposed allocation of costs for OOM calls is not equitable. One of the circumstances, other than a transmission facility outage or a location-specific requirement, that could result in an OOM call is bid insufficiency. Under the proposal, costs associated with such calls would be spread to all SCs in proportion to their metered Demand (including Exports). If there are insufficient bids in real-time, then one or more SCs must be deviating from their final balanced schedules. In this case, costs associated with the resulting OOM call or calls should be assessed against those SCs with an imbalance, rather than allocated to all SCs.
IEP	IEP understands that the proposed Tariff language would only apply when the ISO has insufficient supplies of Supplemental Energy, Adjustment Bids, or RMR resources such that the ISO must dispatch resources to address congestion or avoid a system emergency. If this is the case, questions why a generator directed by the ISO to decrement from its schedule would be required to pay the ISO under Section 11.2.4.2(b)(i). Asks why the generator should not, instead, be paid for providing a service it otherwise has indicated (through a lack of decremental bids) that it does not wish to provide. Also asks if this payment would be in lieu of Imbalance Energy charges that would be imposed. Requests additional detail on the energy payment component proposed in Section 11.2.4.2(b)(ii). Asks whether the payment is based on a "weighted average of the PX DA, PX DO and ISO RT markets." Offers a hypothetical of a resource called upon immediately after a two month planned outage and asks what would be the "three most recent similar days" for such a unit. Notes that the term "Exports" should be capitalized throughout the proposed Tariff language.