UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	))	**Docket No. ER04-835-___**

MOTION FOR LEAVE TO FILE ANSWER AND ANSWER OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION TO MOTIONS TO INTERVENE, COMMENTS, AND PROTESTS

I. INTRODUCTION AND SUMMARY

On May 11, 2004, the California Independent System Operator Corporation ("ISO")[1] filed Amendment No. 60 to the ISO Tariff in the above-captioned proceeding ("Amendment No. 60"). Amendment No. 60 proposed to:

- Use a Security-Constrained Unit Commitment ("SCUC") application to minimize must-offer commitment costs;
- Revise the gas cost proxy used in the Minimum Load Cost Compensation ("MLCC") payment and Start-Up payments;
- Include auxiliary power as a recoverable Start-Up cost;
- Eliminate the current practice of rescinding MLCC payments when a unit provides Ancillary Services;
- Revise the timing of the must-offer waiver denial process to facilitate bidding into the Day-Ahead Ancillary Services markets;
- Clarify Self-Commitment and its implications for MLCC payment;
- Revise how MLCC costs are allocated; and
- Establish a framework for using Condition 2 RMR Units outside of the Reliability Must-Run ("RMR") Contract.

A number of parties have submitted motions to intervene, comments, and protests concerning Amendment No. 60.[2] The ISO does not oppose the

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[1] Capitalized terms not otherwise defined herein shall have the meaning set forth in the Master Definitions Supplement, Appendix A to the ISO Tariff.

[2] The following entities filed timely motions to intervene, comments, requests for clarification and/or protests: The Cities of Anaheim, Azusa, Banning, Colton, and Riverside,

interventions of parties that have sought leave to intervene in the proceeding. Moreover, a number of the parties explain that they support some or all of the principles contained in Amendment No. 60, the specific proposals in Amendment No. 60, or both. However, some parties also raise concerns and protests with regard to certain aspects of Amendment No. 60. Pursuant to Rules 212 and 213 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §§ 385.212, 385.213, the ISO hereby requests leave to file an answer, and files its answer, to the comments and protests submitted in this proceeding.[3] As explained below, the Commission should accept Amendment No. 60 in its entirety, except for the limited modifications noted below.

California ("Southern Cities"); the Cities of Redding and Santa Clara, California and the M-S-R Public Power Agency (together, "Cities/M-S-R"); California Electricity Oversight Board ("EOB"); California Department of Water Resources State Water Project ("CDWR-SWP"); California Municipal Utilities Association ("CMUA"), California Public Utilities Commission ("CPUC"); Calpine Corporation ("Calpine"); Duke Energy North America LLC and Duke Energy Trading and Marketing, L.L.C. (collectively, "Duke Energy"); El Segundo Power, LLC, Long Beach Generation LLC, Cabrillo Power I LLC and Cabrillo Power II LLC (collectively, "West Coast Power", or "WCP") and Williams Power Company LLC ("Williams" and together with WCP, "WCP/Williams"); the Independent Energy Producers Association ("IEP"); the Metropolitan Water District of Southern California ("MWD"); Mirant Americas Energy Marketing LP, Mirant California, LLC, Mirant Delta, LLC and Mirant Potrero, LLC (collectively, "Mirant"); Modesto Irrigation District ("MID"); Northern California Power Agency ("NCPA"); Powerex Corporation ("Powerex"); Reliant Energy Power Generation, Inc. and Reliant Energy Services, Inc. (collectively, "Reliant"), Sacramento Municipal Utility District ("SMUD"); and Transmission Agency of Northern California ("TANC"). The following parties submitted interventions, comments and protests out of time: City of Vernon, California; Pacific Gas and Electric Company ("PG&E"); Southern California Edison Company ("SCE"); and Turlock Irrigation District ("TID"). The ISO does not oppose these late motions. The Los Angeles Department of Water and Power's filing, although timely, was posted in the wrong docket number at the Commission, and the ISO did not realize this in time to respond to arguments discussed therein. In addition, San Diego Gas & Electric Company's filing was so seriously out of time that the ISO did not have the opportunity to respond to it in this pleading.

[3] To the extent this answer is deemed an answer to protests, the ISO requests waiver of Rule 213 (18 C.F.R § 385.213) to permit it to make this Answer. Good cause for this waiver exists here because the answer will aid the Commission in understanding the issues in the proceeding, provide additional information to assist the Commission in the decision-making process, and help to ensure a complete and accurate record in this case. *See, e.g.*, *Entergy Services, Inc.*, 101 FERC ¶ 61,289, at 62,163 (2002); *Duke Energy Corporation*, 100 FERC

II. ANSWER

A. The Remedies Sought By Several Parties are Beyond the Scope of the Must-Offer Stakeholder Process

As described in the Amendment No. 60 transmittal letter, the ISO instituted a series of stakeholder meetings to respond to complaints that the must-offer process was not transparent or well understood. The stakeholder meetings were intended: (1) to provide more detailed explanations of how the ISO dispatches and pays units called under the must-offer obligation; (2) to provide a forum for examining the current must offer process (including the must offer waiver process); and (3) to review options for short-term improvements in the way the ISO was implementing the must-offer requirement. The must-offer stakeholder process was not intended to circumvent or substitute for the CPUC's ongoing resource adequacy proceeding and was not intended to re-examine and revise the RMR designation criteria. The ISO commenced a separate effort in that regard by hosting a stakeholder meeting on May 24. Further, the must offer stakeholder process was not intended to address local market power mitigation measures.

It is readily apparent that very few Market Participants are satisfied with the status quo. Some are pressing for the abolition of markets and the return to the fully regulated vertically integrated paradigm. Others are pressing the ISO to accelerate implementing its MD02 market redesign. In the midst of this contentious environment, the ISO must reliably operate a bulk electric power

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¶ 61,251, at 61,886 (2002); *Delmarva Power & Light Company*, 93 FERC ¶ 61,098, at 61,259 (2000).

system, administer its current tariff and run the ISO Markets that pose their own set of new and old challenges each day, improve its stakeholder processes , and proceed with its market redesign in a prudent way. In developing the Amendment No. 60 proposal, the ISO sought to balance the competing interests of suppliers and load serving entities. Under these circumstances, it is not surprising that many of the comments have offered partial support. The fact that such a broad range of Market Participants has found competing issues to praise and fault, demonstrates the ISO has made an equitable proposal that should be adopted by the Commission.

As the Commission reviews the protests to and comments on Amendment No. 60, the ISO requests that the Commission bear in mind the necessarily limited scope of the must-offer stakeholder process and the resulting Amendment No. 60. As the filing entity, the ISO has the sole right to determine the scope and content of its Section 205 filings. *Atlantic City Electric Company, et al, v. FERC,* 295 F.3d 1 (D.C. Cir. 2002). Issues such as the need for a resource adequacy program, reformation of the RMR unit selection criteria, or implementation of compensation/mitigation measures recently adopted in the Commission's May 6, 2004 Order in Docket No. EL03-236, *PJM Interconnection, LLC*, 107 FERC ¶ 61,112 (2004) ("Reliability Compensation Order") go beyond the scope of the ISO's submission and should not be countenanced by the Commission. *ANR Pipeline Co.,* 63 FERC ¶ 61,231 at 62,633 (1993).

B. The Must-Offer Stakeholder Process was not Informed by the PJM Reliability Compensation Order

A number of parties assert that the Commission should evaluate Amendment No. 60 in the context of the principles advanced in the May 6 PJM Reliability Compensation Order. That order was issued five days before the ISO tendered Amendment No. 60 for filing. Accordingly, the principles enunciated in that order were not available to inform the stakeholder process that resulted in Amendment No. 60.

As indicated above, the must offer stakeholder process commenced eight months ago with a **single** objective – to improve the current must-offer process. No party disputes that an extensive stakeholder process was held and that all issues raised by the Amendment 60 filing were thoroughly vetted. The ISO's must offer filing does not address – and the must offer stakeholder process did not address -- generic RMR issues or local market power mitigation issues. On the other hand, the issues in the PJM proceeding that culminated in the May 6, 2004 order arose in the context of determining the appropriate compensation for RMR units and appropriate local market power mitigation measures (including price caps). Not only were the specific issues raised in the PJM proceeding not addressed in the must offer stakeholder process, the specific principles adopted by the Commission in the Reliability Compensation Order were not addressed, either.

Moreover, a primary issue in *PJM* was whether units needed for local reliability service were being "overly-mitigated" under PJM's local market power mitigation scheme and, thereby, not receiving revenues that were compensatory for the service they were being provided. A PJM-like discussion of reliability compensation issues was outside of the scope of must-offer stakeholder process. Given that the Reliability Compensation Order raises significant brand new issues, it would be unfair and inappropriate to apply such principles to the Amendment 60 filing absent the convening of a brand new stakeholder process to address such matters. Such additional process would only delay implementation of transparency, compensation, and cost allocation measures that are needed now - not many months down the road. In that regard, the ISO notes that the process in PJM (from commencement of a stakeholder process to issuance of a Commission order) took approximately 9-10 months. The ISO and Market Participants should not wait that long to improve the current must offer process.

The Reliability Compensation Order recognizes that there is not a "standard regulatory response" to the set of issues raised in the PJM proceeding, and the Commission will examine the specific circumstances in each market in arriving at a solution. Reliability Compensation Order at P 15. Thus, the Commission cannot – as some parties would like – simply rubber stamp the Commissioned-approved mechanisms in the Reliability Compensation Order onto the ISO's market design. In any event, the Amendment 60 proposal is not inconsistent with the general principles enunciated in the Reliability Compensation Order. In that regard, the Short-Term Reliability Compensation

Issues[4] identified in the PJM Order relate principally to the appropriate compensation for units needed for reliability and which are subject to mitigation that causes them to receive non-compensatory revenue which impacts their ability to provide service. No party is alleging in this proceeding that the ISO's mitigation measures are precluding them from earning compensatory revenues, and such issue was beyond the scope of the stakeholder process and the Amendment No. 60 filing. Thus, the driving issue in PJM, *i.e.,* the impact of price mitigation, is not present here. Indeed, the ISO has the weakest local market power mitigation measures of any functioning independent system operator. For the reasons set forth in the Amendment No. 60 filing and herein, the ISO is providing fair and compensatory service to suppliers for the real-time service they are supplying. In particular, the ISO proposal will provide increased compensation for suppliers' Start-up and Minimum Load costs. The ISO's proposal also will allow suppliers to provide Ancillary Services and still receive Minimum Load Cost Compensation.

Amendment No. 60 proposes a package of modifications, which benefit (and disadvantage) different groups of stakeholders. No stakeholder either supports or rejects all the provisions of Amendment No. 60. In the ISO's opinion, the filing reflects an adequate balance of parties' interests regarding

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[4] With respect to Long-Term Reliability Compensation Issues, the ISO is in the process of overhauling its market design via the MD02 process. In addition, the ISO has kicked off the 2005 RMR process, and any issues raised in the PJM proceeding logically should be addressed in that process, which is comparable to the process that led to the Reliability Compensation Order. Finally, the California Public Utilities Commission is in the process of developing a final order on resource adequacy and has indicated that the reserve requirement will be phased-in starting in mid 2005.

compensation. Given the pressure from stakeholders to file Amendment No. 60 so as to at least achieve the benefits of those aspects of Amendment No. 60 that favor them,[5] the Commission should promptly approve the filing. The Commission should not delay ruling on Amendment No. 60.

C. There is No "De Facto" Day-Ahead Must-Offer

IEP represents that the must-offer obligation has become a "de facto" Day-Ahead must-offer obligation. IEP at 10. The ISO did not propose to turn the existing real-time must-offer obligation into a day-ahead must-offer obligation in Amendment No. 60. IEP's representation that the current process constitutes a "de facto" day-ahead must-offer obligation ignores the realities of power system operations and the history of the must-offer obligation. As originally proposed by the Commission, the real-time must-offer obligation would require every generating unit subject to that obligation to remain in service so as to be able to offer its available generating capacity in real time. To avoid this result, the ISO proposed, and the Commission accepted, the current waiver process so units not required to operate could be granted a waiver of the must-offer obligation and shut down. The fact that this waiver denial process happens the day before the operating day is determined by the time required to start-up many conventional steam turbines (12 to 24 hours). While the issue of a day-ahead must-offer obligation is being discussed in the context of future market redesign, the current must-offer obligation is not a *de facto* day-ahead must-offer obligation.

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5 Given recent bid insufficiency in the Ancillary Services markets, the ISO acknowledges that it would have been unwilling to delay seeking the elimination of rescinding MLCC payments when a unit provides Ancillary Services.

D. Terminating the Must-Offer Obligation Is Beyond the Scope of the Must-Offer stakeholder process

Several parties request that the Commission terminate the must-offer requirement. IEP at 17; Calpine at 3; Powerex at 4, 5. Such protests are clearly beyond the scope of a submission designed to improve the current must-offer process and thus can only be addressed in accordance with Section 206 of the Federal Power Act. That would require parties to demonstrate – and the Commission to find -- that the existing must offer obligation is not just and unreasonable and that complete elimination of the must offer obligation without any type of replacement mechanism is just and reasonable. Parties have not even come close to making that type of showing.

The Commission instituted the must-offer requirement to prevent market power from being exercised by physical withholding and thereby ensure that the ISO will be able to utilize available resources in real time to the extent additional energy is needed. *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator and the California Power Exchange,* 95 FERC ¶ 61,418 at 62,551 (2001). It is imperative that the Commission maintain the requirement to promote market stability and deter physical withholding in California as the Commission, CPUC, ISO and Market Participants work to overhaul the existing market structure and design and implement a brand new market structure.

E. System Resources Are Not Always Comparable to Generating Units Subject to the Must-Offer Obligation and Cannot Compete With Such Resources

Powerex asserts that System Resources should be allowed to compete to provide the service being provided by units committed under the must-offer obligation. Powerex at 6. While imports are an important source of the Energy needed to serve Demand in the ISO Control Area, imported energy is not always a substitute for Energy procured from within the ISO Control Area. The ISO has acknowledged that much of the Energy procured from generating units committed through the must-offer process is needed to meet locational or zonal requirements within the ISO Control Area and could not be provided from System Resources. Amendment No. 60 Transmittal Letter at 10-11; 32.

The ISO notes that Powerex has many opportunities to participate through bilateral transactions and the submission of Ancillary Service bids to sell energy to load serving entities in California.

F. Challenges to the Must-Offer Requirement Are Inappropriate

As noted above, many of the protests represent collateral attacks on the existing Commission-imposed must-offer requirement and are procedurally inappropriate. Amendment No. 60 seeks only to improve the current process. Moreover, the ISO's proposals need only be just and reasonable, they do not need to be the "best" alternative available. *See New England Power Company,* 52 FERC ¶ 61,090 at 61,336 (1990), *reh'g denied*, 54 FERC ¶ 61,055 (1991), *aff'd*, *Town of Norwood v. FERC*, 962 F.2d 20 (D.C. Cir. 1992) (utility need only establish that its proposed rate design is reasonable, not that it is superior to other alternatives); *OXY USA Inc. v. FERC,* 64 F.3d 679, 692 (D.C. Cir. 1995)

(The Commission may approve the methodology proposed in the settlement agreement if it is "just and reasonable;" it need not be the only reasonable methodology or even the most accurate). Recognizing that challenges to the existence and current implementation of the must-offer requirement can only be raised in Section 206 complaints, the ISO nevertheless responds to certain of the arguments raised in the protests.

1. Short-Term Reliability Contracts are Not A Panacea

IEP recommends that the Commission terminate the current must-offer obligation and direct the ISO to enter into Short-Term Reliability Contracts ("STRCs"). IEP at 17-23. IEP suggests that those STRCs be awarded for terms not less than two months on the basis of "the significant analysis already undertaken in the review of current uses of the [must-offer obligation] informed by recent operating experience, similar to that applied for RMR." IEP at 21. The ISO currently designates Reliability Must-Run units according to criteria approved by the ISO Governing Board in 1999. Specifically, RMR units are those units needed: (1) to meet all Applicable Reliability Criteria following the single largest contingency (loss of a line or transformer) under system peak conditions with the most affected generating unit already out of service and (2) to meet other operational needs. Under current policy, the ISO does not designate units as RMR to address 500-kV limitations under the premise that 500-kV limitations can be addressed by a competitive market. The ISO acknowledges that, under these criteria, the ISO may not designate enough RMR units to meet every local reliability problem. For example, the ISO may not designate RMR units to meet local reliability problems that arise due to unforeseen or temporary transmission outages.[6]

IEP suggests that the ISO designates RMR units based on "recent operating experience". IEP at 21. This is perhaps partially true. The ISO currently designates RMR units on the basis of expected future operations, not on the basis of past experience. To the extent the ISO faces a current operating problem and expects to face that same problem in the future, any RMR unit designated to meet that problem would ostensibly reflect "recent operating experience". While recent operating experience could indicate future need, however, recent operating experience could be a very poor indicator of future requirements. Although IEP contends that the ISO could award STRCs to units based on "the significant analysis already undertaken in review of the current uses of [the must-offer obligation] informed by recent operating experience," IEP provides no guidance as to how the ISO would apply that review and experience to determine which units would be eligible and which units would not. For example, would every unit for which a must-offer waiver was revoked in the last several months be awarded a STCR? If not, where would the threshold be established? Would it be advisable to award STRCs for summer peak season based on spring operating conditions? Or to award STRCs for fall based on summer? While several stakeholders, including IEP, criticized the existing RMR designation process, none offered a specific alternative. Defining the criteria for

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[6] As an example, the ISO committed units for several months under the must-offer obligation to maintain operations in Southern California within local reliability criteria following the transformer failure and fire at Vincent Substation on March 18, 2003.

awarding STRCs would be no less difficult and contentious than defining the threshold for awarding RMR contracts has been.

IEP suggests that the ISO could use its existing tariff authority to assign the STRC costs associated with system (i.e., ISO Controlled Grid-wide) reliability on a load-ratio-share of metered Demand and export and assign the costs of local reliability to the Participating Transmission Owner ("Participating TO") in whose service area the contract unit is located. IEP at 23. IEP is correct in that both of those cost allocation mechanisms currently exist within the ISO Tariff. But those mechanisms exist for different types of contracts.

ISO Tariff Section 5.2.8 indicates that the costs of RMR Contracts are allocated to the Participating Transmission Owner. However, while the ISO has proposed to be able to call on Condition 2 RMR Units outside the RMR Contract under limited circumstances to meet system-wide or zonal reliability needs (i.e., to meet projected Demand or to manage Inter-Zonal congestion) in Amendment No. 60, the ISO cannot call on any RMR Unit, either Condition 1 or Condition 2, to meet system-wide reliability needs or manage Inter-Zonal Congestion under the RMR Contract. To meet those needs, the ISO would have to enter into a contract pursuant to Section 2.3.5. As set forth in 2.3.5.1.8, costs for such contracts are allocated to hourly metered Demand and export. As it currently stands, the Tariff would not allow the ISO to allocate costs incurred under the same contract one way if those costs were incurred for local reliability reasons and a different way if costs were incurred under the very same contract for system-wide or zonal reliability reasons.

WCP notes that the amount of capacity subject to RMR contracts in the Los Angeles Basin has declined to 750 MW in 2004 from a high of 6,030 MW in 1998. WCP at 16. The current RMR requirements in the Los Angeles Basin have been determined in accordance with the RMR designation criteria approved by the ISO Governing Board in 1999. The RMR requirements decreased significantly after 1998 because Southern California Edison upgraded transmission infrastructure to eliminate problems that initially led to more units being designated as RMR. Current operating challenges – such as complying with the Southern California Import Transmission ("SCIT") nomogram – involve inter-zonal interfaces or encompass more than local reliability problems and fall outside of the RMR designation criteria.

In the PJM Reliability Compensation order, the Commission noted that the best ways to address reliability compensation issues are through market design or through long-term bilateral contracts. 107 FERC ¶ 61,112 at P 20. STRCs fit neither of these categories. Implementing STRCs would require the ISO to develop a *pro forma* agreement, a process that took nearly two years for the existing RMR contracts.[7]

2. MOO has become a Resource Adequacy Tool

WCP/Williams asserts that the must-offer obligation has morphed into a Resource Adequacy tool. WCP/WIlliams at 12-13. This assertion is misplaced.

A Real-Time must offer obligation is not a resource adequacy issue. The Real-Time must offer obligation was intended to prevent physical withholding. If a resource owner has available (*i.e.*, operable and not otherwise committed) capacity and can offer that capacity at a bid price of its choosing (up to a specified cap), there is no legitimate reason why the resource owner should not offer such capacity into the Real Time Market. As the Commission has previously recognized, "under competitive conditions, a generator that has available energy in real time should be willing to sell that energy at a price that covers its marginal costs, since it has no alternative purchaser at that time." *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator and the California Power Exchange*, 95 FERC ¶ 61,115, at 61,355-56 (2001). A real-time must offer obligation protects consumers against physical withholding and promotes stable and competitive markets. As such, it should be a permanent feature of any market, with or without a resource adequacy program.

Further, in the Commission's *White Paper on Wholesale Power Market Platform* ("White Paper") issued on April 28, 2003, in Docket No. RM01-12, the Commission determined that

> [w]e will not include a minimum level of resource adequacy [in SMD]. The RTO or ISO may implement a resource adequacy program only where a state (or states) asks it to do so, or where a state does not act.

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[7] Even after nearly two years, a substantial number of issues remained unresolved. *See* the Stipulation and Agreement filed on April 2, 1999 in Docket Nos.ER98-441, *et al*.

White Paper at 5.[8] Thus, the Commission has placed the responsibility for resource adequacy squarely with the states. As the Commission and WCP/Williams are well aware, the CPUC is currently in the process of developing a resource adequacy plan, and a final order on resource adequacy is expected in September 2004. The Commission has directed the ISO to make a compliance filing within 60 days after the CPUC issues its final order on resource adequacy to identify any changes that will be necessary to the ISO's long-term market re-design proposal.

Duke notes that it is unclear how the ISO was complying with Applicable Reliability Criteria prior to the must-offer obligation if the ISO is now meeting those criteria by committing units through the must-offer obligation. Duke at 3. While Applicable Reliability Criteria have largely remained the same over the past several years, system conditions have changed. Some of the situations in which the ISO has committed units under the must-offer obligation – such as the SCIT nomogram – did not constrain system operations in the past. The SCIT nomogram now constrains operations due to the addition of large amounts of new generation in Arizona. Additionally, when there were more units under RMR Contracts in SP15 than now, the ISO could call on those additional RMR Units to meet local reliability needs, even if the need arose from a situation not covered under the RMR designation criteria, such as a need that arose from a planned transmission outage. In other circumstances, the ISO called on out-of-sequence

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[8] SMD means the Commission's proposed Standard Market Design, which was first described in detail in the Notice of Proposed Rulemaking issued in Docket No. RM01-12-000 on July 31, 2002 ("SMD NOPR").

bids of non-RMR resources to meet reliability criteria – just as it does today when it must dispatch a unit committed under the must-offer obligation out-of-sequence according to its bid for local reliability requirements. The ISO has used and continues to use out-of-market calls as needed to comply with reliability criteria.

CMUA asks the Commission to direct the ISO to convene a stakeholder process outside the CPUC Resource Adequacy process to develop the criteria that would allow load serving entities ("LSEs") to self-provide capacity requirements. CMUA at 7-8. The ISO is already in the process of sharing information that will help LSEs meet their capacity requirements. In a June 10, 2004 letter from ISO Vice President of Grid Operations Jim Detmers to SCE Vice President of Power Procurement Pedro Pizzaro, the ISO committed to providing information that would help LSEs determine local reliability requirements, noting:

> As a first step, the ISO is currently identifying and preparing for publication all generic system and local area information that would assist SCE and others in making procurement and scheduling decisions that are aligned with the ISO's reliability requirements. Such information could include, among other information: 1) all applicable system and local area operating procedures and nomograms, such as the Southern California Import Transmission ("SCIT") nomogram; 2) areas of chronic intra-zonal congestion and the extent and cost of ISO real-time redispatch instructions to alleviate such congestion; 3) information regarding, on an aggregate basis, the generation the ISO commits on a regular basis through the existing must-offer waiver process to satisfy reliability requirements; 4) all grid outages that impact transfer capability, including not only outages at the interconnection points with other control areas, as is currently done, but also for internal grid facilities the availability of which impacts the congestion areas at issue.

Other LSE capacity requirements are currently being addressed in the CPUC Procurement proceeding. The ISO has also been an active participant in that proceeding, and there is no reason to establish a separate competing process to accomplish the same result. As indicated above, the Commission has deferred resource adequacy to the states in the first instance.

3. Existing Ancillary Services Markets Are Not a Substitute For the Must-Offer Obligation

Several parties propose that the ISO purchase the capacity it requires through the existing Ancillary Services markets rather than by committing units under the must-offer obligation. PG&E at 7; WCP/Williams at 31. The ISO described why the existing Ancillary Services markets cannot be used to acquire all the capacity the ISO requires to be on-line in the Amendment No. 60 transmittal letter.[9] In summary, the existing Ancillary Services markets are not and should not be unit commitment markets and are designed to procure a fungible reserve product from the entire Control Area (or, at least, within a Congestion Zone), not to procure capacity specific to a location within the ISO Controlled Grid.

When the California PX was in operation, California had a Day-Ahead wholesale energy market that generated unit commitments resulting from supply and demand meeting in advance of real-time in addition to those commitments made via bilateral transactions. This unit commitment process added to the amount of online capacity that was available in real-time to provide both unloaded capacity for system reserves and volume in the Imbalance Energy market. Since the PX closed, the Must Offer Obligation is the only mechanism

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[9] Amendment No. 60 Transmittal Letter at 15.

outside bilateral transactions that ensures both sufficient depth to the imbalance energy market and sufficient online capacity for system reserves.

The existing Ancillary Service markets evaluate bids for capacity only and are designed to procure Regulation and Operating Reserves at least cost. They are not designed to perform the function of unit commitment for purposes of maintaining online capacity and depth in the Imbalance Energy market.[10] Using the existing Ancillary Service markets (in place of the Must Offer Obligation) as a unit commitment mechanism in addition to these markets' intended function will result in unit commitments that do not meet the ISO's derived locational need for capacity and/or energy. *See* discussion under Section M, below, for additional comments on this issue.

G. Transparency

CMUA contends Amendment No. 60 does not provide enough information to allow Market Participants to scrutinize operational decisions. CMUA at 2, 4-5. While CMUA advocates transparency, it does not specifically indicate what information it deems as necessary for the ISO to provide. Through the must-offer stakeholder process, the ISO agreed to post information regarding use of must-offer resources, including the total number of units, total MW of minimum load energy, total MW capacity and total minimum load costs, categorized by Zone and by the reason why the unit was committed (e.g., for local, zonal or system

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10 The existing Ancillary Service markets are not designed to evaluate three-part bids (start-up, minimum load, and capacity) for optimizing over commitment, energy, and capacity.

requirements). Unit-specific information is likely commercially sensitive data and could not be posted in accordance with Section 20.3 of the ISO Tariff.

CMUA asserts that the ISO should make specific operating protocols available for stakeholder consideration and then file those operating procedures as part of a compliance filing. CMUA at 6. WCP also asserts that the ISO should be required to finalize and file Operating Procedure M-432. WCP at 17-18. While chastising the ISO for not being transparent, CMUA does not describe which specific operating protocols it wants the ISO to make available and file. ISO operating procedures, including M-432C, are already available to market participants on the ISO web site. [11] The ISO commits to finalizing and re-posting M-432C procedure by July 12, 2004.[12]

IEP contends that the proposed timeline for publishing must-offer data is too long and unjustified. IEP at 27. If the purpose of posting this information is to allow Market Participants to provide transparency so as to scrutinize ISO system operations and to verify ISO charges, the proposed 30-day lag should impose no burden. The ISO is concerned that providing information with less than a 30-day lag could encourage Market Participants that could exercise market power based on their location relative to a particular constraint to do so. While the information may also help Market Participants adjust their scheduling practices so as to

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[11] At http://www.caiso.com/thegrid/operations/opsdoc/. Some information is not available in this public posting of the ISO Operating Procedures due to security or confidentiality reasons. Third party operating procedures and unit-specific data are not being provided pending ISO and third party confidentiality review. Names and phone numbers are excluded for privacy and security reasons. Emergency restoration procedures are not included due to security considerations.

[12] http://www.caiso.com/docs/09003a6080/29/b7/09003a608029b733.pdf.

reduce the possible exercise of market power, in situations in which there are few suppliers that bear on a given constraint the potential to exercise market power outweighs any benefit that might counterbalance that potential. The 30-day lag is a reasonable delay (especially given the current timing of ISO market invoices) and no party provides sufficient justification why this lag should not be adopted.

SCE requests that the ISO provide the information sufficient for market participants to understand the operating criteria or reliability need driving the must-offer waiver denial. SCE at 2. As noted above, the ISO has committed to making information available that would assist LSEs in procuring capacity that would also meet local area reliability needs. This information can also be used to understand the reliability needs driving the must-offer waiver denial.

PG&E requests that the ISO provide additional detail on why the ISO needs “margin” above other mandated reserve requirements. PG&E at 7. PG&E also asks the ISO for further information on why the ISO cannot procure those reserves through the existing Ancillary Services markets. *Id.* Finally, PG&E asks how the ISO specifically proposes to determine total [capacity] needs, including mandated reserves, local area capacity and the “margin”. *Id.* The ISO described why it procures additional reserves beyond those minimum requirements established by Applicable Reliability Criteria in the Amendment No. 60 transmittal letter. Amendment No. 60 Transmittal Letter at 2-3. In Section II.F.3 of the instant filing, again citing to the explanation it provided in the Amendment No. 60 transmittal letter, the ISO reiterates why the capacity required for reliable operations cannot always be procured through the existing Ancillary Services markets. To PG&E's final request: the reserve requirement for mandated compliance with reliability criteria is set forth in those criteria; the capacity requirements for local area requirements can be ascertained from ISO operating procedures and other information the ISO has indicated it will provide; and the "margin", as described in the Amendment No. 60 transmittal letter, is not formulaic, but determined based on operating experience and current conditions.

H. Implementation of SCUC Will Lead To Improved Dispatch Decisions to Meet Overall System Needs

Parties both support and object to the use of a Security-Constrained Unit Commitment ("SCUC") application to commit must-offer units to meet zonal and system requirements at least cost. PG&E and SMUD support the use of the SCUC application. PG&E at 3-4; SMUD at 1. IEP and WCP/Williams oppose the use of the SCUC application on the grounds that because the application (as initially implemented) will not use a full network model and therefore will not consider all local reliability requirements, it is of limited value because most of the must-offer unit commitment stems from local reliability requirements. Calpine at 3. IEP at 25-26. WCP/Williams at 19.

The ISO acknowledges that many of the units currently committed through the must-offer process are committed for local reliability reasons, and that the initial implementation of the SCUC application would not affect those units. However, in the situation in which the ISO must commit a particular unit or set of units to address a local reliability problem, the SCUC application could not lower the overall cost anyway because there is no choice among units to commit.

Furthermore, the SCUC application is needed to support the three-part cost allocation proposed. *See* Amendment No. 60 Transmittal Letter at 35-36.

Calpine also opposes the use of an SCUC application because considering economics will cause the same newer, more efficient units to be repeatedly committed. Calpine at 4. While the ISO agrees the SCUC application would tend to commit newer, less expensive units first, the ISO expects that these newer, efficient generating units would, under most conditions, be selling power and already operating on their own and not asking for a waiver. If an efficient unit is available, it seems reasonable to assume it will be operating. Calpine's concern therefore seems misplaced. In any event, the Commission has approved the use of a least-cost security constrained unit commitment for other independent system operators. *See Midwest Independent Transmission System Operator, Inc.,* 102 FERC ¶ 61,196 (2003); *New York Independent System Operator, Inc.,* 97 FERC ¶ 61,242 (2001). Just as these independent system operators are permitted to optimally commit the lowest cost units every day, so should the ISO.

MWD asserts that the ISO contradicts itself by claiming to not want to implement the Residual Unit Commitment ("RUC") mechanism rather than continue with the must-offer obligation because the ISO didn't want to implement MD02 on a piecemeal basis, but then proposing to implement the SCUC application, which is integrally related to the implementation of Locational Marginal Pricing. MWD at P 27. MWD apparently misunderstands the nature of the SCUC application the ISO proposed as part of Amendment No. 60. The ISO proposed to implement SCUC using the existing zonal congestion management model (i.e., with only the inter-zonal constraints modeled). Amendment No. 60 Transmittal Letter at 16. It is true that the SCUC application engine could later be fitted to a full network model (i.e., one with all transmission constraints enforced) to serve as the backbone for a RUC process in a Locational Marginal Pricing paradigm. That is not what the ISO proposed for Amendment No. 60. The full network model, not the SCUC engine, is what is needed to implement Locational Marginal Pricing.

Ultimately, the ISO would like to implement a full network model in the SCUC application so that the must-offer units can be committed at least cost considering all transmission constraints. The ISO has proposed a less ambitious initial implementation of the SCUC engine that will still help reduce the costs of units committed to meet zonal and control-area wide needs and will support the "incremental" allocation of local reliability-related must-offer costs. The ISO respectfully urges the Commission to approve the use of the SCUC application.

MWD does not support running the SCUC engine twice to determine the incremental cost of local reliability. MWD questions whether running the SCUC will evidence the dispatch of a unit for both local and system reasons. MWD at P 26. Running the SCUC twice will not, in fact, show whether a unit is dispatched for local reliability or system needs. SCUC will not determine whether a unit is committed for local requirements. The ISO will commit those units needed for local reliability outside the SCUC application and model those units as "must-run". SCUC will then determine the costs of running those units, as well as the costs of committing other units that may be needed for system and zonal requirements. In the second pass of SCUC, all units committed for local reliability will be turned off. If SCUC commits those units in the second run, then these units were needed for local reliability and were the least expensive units to commit for system needs. If the units remain shut off in the second run, they were needed only for local reliability. What the ISO proposes to allocate to the Participating TO(s) is the area-specific difference between the costs of the first run and the costs of the second run.

I. The ISO's Proposed Cost Allocation Is Reasonable

1. Amendment No. 60 Follows the Principles of Cost Causation

Practically every intervenor that comments on the issue of cost allocation states that the ISO must follow principles of cost causation when allocating Minimum Load Costs. *See, e.g.*, IEP at 26; PG&E at 4. The ISO's proposal to allocate Minimum Load Costs follows cost-causation principles. Costs due to local reliability concerns are allocated locally to the Participating Transmission Owner, like RMR charges. Costs due to constraints on transferring power into a zone are allocated to Demand in that one. Costs due to system-wide requirements are allocated system-wide, first to Net Negative Uninstructed Deviation, then to metered Demand and in-state exports. This tiered cost allocation reflects better cost causation principles than the current method of allocating all charges, regardless of reason, to all metered Demand within the ISO control area and exports.

2. Amendment No. 60 Reasonably Allocates A Portion of Must-Offer Costs To Exports

SMUD asserts that the ISO should not allocate must-offer costs to either exports or wheel-through schedules. SMUD at 4-7. SMUD asserts that wheel-through schedules impose "a zero burden" on the ISO. *Id.* SMUD points out that due to the current allocation of must-offer costs (to metered Demand within the ISO Control Area and exports to Demand within California), a wheel-through transaction that begins in the Bonneville Power Administration's Control Area through the ISO Controlled Grid and terminates in SMUD's Control Area is allocated Minimum Load Costs, while a wheel through the opposite way (beginning with SMUD and ending with BPA) would not be allocated Minimum load costs. *Id.*

When the Commission established the existing cost allocation regime for emissions costs, the Commission indicated it was appropriate for these costs to be allocated to all in-state load served from the ISO's system because all California customers benefited from cleaner air.[13] The Commission also directed that start-up fuel costs be allocated the same way as emissions costs.[14] Finally, when directing the ISO to pay minimum load costs, the Commission directed the ISO to allocate those costs in the same way as emissions and start-up fuel costs.[15]

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13 *San Diego Gas & Electric Company*, 95 FERC ¶ 61,418 at 62,562 (2001).

14 *Id.* at 62,548.

15 *San Diego Gas & Electric Company*, 97 FERC ¶ 61,293 at 62,363 (2001).

Given that the ISO has proposed to allocate must-offer costs incurred for local reliability and zonal needs differently to better reflect cost causation principles, and similarly to allocate system-wide charges first to Net Negative Uninstructed Deviation, and then to metered Demand and in-state exports, the volume of must-offer costs allocated to metered Demand and in-state exports should be greatly reduced and SMUD's concerns about must-offer costs ameliorated. While wheel-through schedules do not impose a "zero burden" on the ISO and ISO Controlled Grid (their energy can contribute to congestion and must be appropriately tracked and settled), wheel-through schedules do not impose the same burden as other import or export schedules. Over the last few years, the ISO has examined its catalog of charge types to evaluate which charge types should apply to wheel-through schedules. That effort is still under way, and the ISO may revisit this issue in the future.

3. Capping the Allocation to Negative Uninstructed Deviations

The ISO has proposed to eliminate the current sweeping allocation of Minimum Load Costs to metered Demand and in-state exports, allocating only those Minimum Load Costs uplifts incurred for Control-Area wide needs below or equal to a capped rate to Net Negative Uninstructed Deviation ("NNUD"), with the remainder to metered Demand and in-state exports. First, CDWR directs that the ISO provide examples of where a must-offer unit is committed to provide zone-wide benefits, and to explain why the ISO may have to commit a unit to manage inter-zonal congestion. CDWR at 8-9. A unit committed to help meet the SCIT nomogram provides zone-wide benefits, because that nomogram governs imports into the entire SP15 region over a variety of transmission paths. The SP15 Congestion Zone contains more than one Participating TO. The SCIT nomogram relates total import capability to the level of inertia (i.e., the total rotating mass of the generating units operating) in the area; committing generating units increases the total import limit, which benefits the entire zone.

CDWR asks why the ISO might incur system-wide must-offer costs when there is little or no NNUD to allocate them to. CDWR at 9-10. In the short-term, this could happen when the ISO commits additional units to meet its Demand forecast (and that Demand forecast is greater than the demand reflected in forward schedules), and a sudden change in weather causes the actual Demand to be much smaller than forecast. The ISO recognizes that due to the monthly allocation of these it is less likely that there would be little or no NNUD. If must-offer costs are allocated daily, as the ISO offers in Section (II)(I)(7) of the instant filing, then it is more likely that there could be small volumes of NNUD on a given day.

Second, several parties protest any allocation of Minimum Load Costs on the basis of metered Demand and in-state exports. TANC asserts that the ISO has not justified that cap on allocating Minimum Load Costs to NNUD. TANC at P 24. MWD asserts that Minimum Load Costs should be fully allocated to NNUD. MWD at PP 21-22. The ISO believes it is appropriate to include a cap on allocating costs to NNUD to prevent a limited group of participants from bearing potentially unreasonable costs. The Commission approved a similar limit with respect to the allocation of above-Market Clearing Price costs approved by the

Commission in Amendment No. 42. *California Independent System Operator Corporation*, 98 FERC ¶ 61,327 at 62,379 (2002).

4. The ISO Has Appropriately Explained the Classification of MOO Costs

Some parties contend that the ISO must define standards it will use to classify MOO costs. Southern Cities at 4. MWD asserts that the ISO has not described how the costs of a non-RMR unit committed and dispatched for local and system reliability needs will be allocated. MWD at P 26. The ISO, however, submitted that information in Attachment E to Amendment No. 60.

5. Settlements Information

Some parties argue that the ISO should provide settlements information to validate cost allocation. Southern Cities at 4. The ISO agrees in principle and will work with Scheduling Coordinators in the design of the detail Settlements detail files prior to implementation.

6. The ISO's Proposed Definition of Reliability Service Costs Is Reasonable and Appropriate

Several parties oppose the proposed definition of Reliability Services Costs. Cities/M-S-R protest that the proposed definition does not have a functional purpose or application to the ISO Tariff. Cities/M-S-R at P 18. TANC asserts that the definition has "no useful application" to the ISO Tariff and was included to "pre-determine the recovery of such costs by Participating TOs." TANC at P 22. The ISO included the proposed definition because it accurately reflects the fact that when a unit is committed for local reliability reasons, those costs are legitimately "Reliability Services Costs", just as RMR costs are. The ISO proposes to allocate such costs to the Participating TO just as RMR costs are allocated. While the ISO believes Participating TOs should be able to recover these costs in rates, Amendment No. 60 takes no position with respect to how these costs should be allocated among the Participating TO customer classes.

CDWR urges the Commission to reject the proposed definition because it conflicts with the Commission's ruling that the ISO can incur costs only for facilities under ISO control.[16] CDWR's argument is misplaced. The ISO incurs costs under the must-offer obligation to ensure the reliability of the ISO Controlled Grid. In effect, these expenses are no different than out of market or "OOM" costs, RMR costs, or ancillary service costs that are incurred to support system operational requirements.

7. Use of Peak-Demand Allocation

CDWR contends that Minimum Load Costs and Start-Up Costs should be allocated to load using the grid in the following day's peak hours (Hours Ending 7 through 22). CDWR at 3-6. While the ISO proposed to allocate must-offer costs on a monthly basis, the ISO, after further evaluating the changes needed to allocate costs on a more granular basis, now believes that allocating these costs daily (not hourly) is both feasible and more appropriate than allocating them on a monthly basis. While the ISO is willing to allocate costs on a daily basis, the ISO would allocate costs based on totals for all hours in the day, not just on the peak hours (hours ending 7 through 22). If the Commission agrees that must-offer costs should be allocated on a daily basis, it will so direct and the ISO will file the appropriate language in its compliance filing.

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16 *California Independent System Operator Corporation*, 107 FERC ¶ 61,152 (2004).

8. Allocation of costs after the implementation of Phase 1B.

As part of Amendment No. 54, the ISO proposed to treat Minimum Load energy as Instructed Imbalance Energy, pay that energy the market clearing price for Imbalance Energy, and pay an additional uplift, if necessary, if the market clearing price was less than the unit's Minimum Load Costs. *See* Third Revised Sheet No. 184D.01, Section 5.11.6.1.1. Under this paradigm, the costs of the Minimum Load Energy would be allocated to those parties purchasing that Energy, and the only Minimum Load Costs allocated separately would be those uplift costs needed to ensure the unit receives its Minimum Load Costs if the market clearing price was less than the Minimum Load Costs. Prior to Phase 1B, Minimum Load Energy is not Scheduled or treated as Instructed Imbalance Energy Costs are paid, so the full Minimum Load Costs are allocated on the basis of metered Demand and in-state exports.

In the post-Phase 1B Tariff language submitted in Amendment No. 60, the ISO did not make clear that the only Minimum Load Costs it would be allocating according to the cost-causation principles set forth are the uplift costs, not the full cost of the Minimum Load Energy. The ISO therefore proposes to correct the tariff language in a compliance filing in the following manner, with the underlined, bolded text signifying a change: In Section 5.11.6.1.4, "Allocation of Minimum Load Costs" the ISO would correct the final sentence of the first paragraph to read: "For each month, the ISO shall sum the Settlement Interval Minimum Load Cost compensation <u>**uplifts settled per Section 5.11.6.1.1**</u> and shall allocate those costs as follows…" Similarly, in subparagraph 1) of Section 5.11.6.1.4, the initial phrase would be revised to read "if a Generating Unit was operating to meet local reliability requirements, the **amount of the Minimum Load costs' uplifts attributed to the** incremental locational cost shall be allocated…." Finally, in subparagraphs 2, 3, and 3(a), the term "uplifts" would be inserted after the phrase "Minimum Load Costs'" or Minimum Load Cost".

9. The ISO Has Provided Sufficient Detail on How Costs will be Allocated

ISO should provide details on how RS costs will be allocated to SCs and PTOs (SMUD, p.2). The ISO described how these costs would be allocated in the Amendment No. 60 transmittal letter (at 32-26). Moreover, the ISO described how it determines if a unit is committed for local, zonal or system needs in Attachment E to Amendment No. 60

10. Reopening the Stakeholder Process To Consider Cost Allocation Further Is Neither Necessary Nor Appropriate

TANC asserts that many affected parties didn't participate in the must-offer stakeholder process because of the perception that the process only dealt with the must-offer obligation and generating unit compensation. TANC at P 16. TANC is correct in that the initial stakeholder meetings focused on operational and compensation issues rather than on cost allocation issues. However, o

n January 14, 2004, the ISO posted a position matrix soliciting feedback on how must-offer costs should be allocated (Question 4-2). The agenda for the March 10, 2004 must-offer stakeholder meeting, posted on March 4, 2004, noted that cost allocation would be part of the discussion.

TANC asserts that only load using New Firm Use transmission across inter-zonal interfaces should be allocated Minimum Load Costs, not all load within the Congested Zone. TANC at P 23. All load in the congested zone – including the load served by non-New Firm use Transmission (*e.g.*, served by energy transmitted using ETC transmission rights) – benefits from the congestion mitigation provided by the must-offer unit. It is possible that load using New Firm Use transmission would have to find another source of energy if the path was congested and transfer across it limited. It is therefore equitable and reasonable that all the must-offer costs incurred be allocated to all Demand within the congested Zone.

TANC requests that the Commission direct the ISO to reconvene the must-offer stakeholder process to examine the cost allocation issues. TANC at P 25. This is unwarranted given the likelihood, based on evaluation of 2003 must-offer costs,[17] that significant must-offer costs will be allocated to TANC if the Commission accepts the ISO's proposed cost allocation, as long as TANC does not incur substantial Net Negative Uninstructed Deviations. The vast majority of local reliability costs (which are allocated to Participating TOs anyway) are likely to be incurred in SP15. The amount of 2003 Minimum Load Costs projected to be allocated to ISO Control Area metered Demand and in-state exports was only $1.7 million.

J. Application of Tolerance Band in Intervals After Dispatch Instruction

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[17] *See* http://www.caiso.com/docs/09003a6080/2e/6e/09003a60802e6e19.pdf.

Several parties protest the ISO's application of the Tolerance Band in intervals after a Dispatch Instruction has been terminated and a unit should be returning to its Minimum Load Level. Duke at 7; WCP/Williams at 33-38. WCP/Williams protest that this practice is not set forth in the ISO Tariff. WCP/Williams assert that the ISO cannot accurately calculate the amount of residual energy the unit will produce while returning to minimum load from a Dispatch Instruction because the ISO will not be able to model multiple ramp rates until the Phase 1B modifications are put into place. *Id*.

The ISO is concerned that without this mechanism in place to encourage units to return to their minimum load levels after a Dispatch Instruction has expired, a unit has no incentive (other than the uninstructed imbalance energy price, which, if high enough, could be an incentive to generate above Minimum Load) other than reasonably conditioning paying its Minimum Load Costs on the unit's prompt return to its Minimum Load Operating Level. Arguably, without this provision, the ISO would never know when to begin applying the Tolerance Band to condition Minimum Load Cost payment (as approved by the Commission) to any unit that is dispatched off its minimum load level.

While the Commission directed the ISO to be able to account for multiple ramp rates before applying Uninstructed Deviation Penalties ("UDP") – which apply to the unit's full range of operation – the Commission has never imposed the same condition on rescinding Minimum Load Cost Compensation. The Phase 1B modifications, which provide for multiple ramp rates, will improve unit operations modeling. Until then, unit owners that wish to ensure that their units can ramp back to the minimum load operating level quickly enough to avoid the loss of Minimum Load Cost Compensation are free to amend their units' ramp rates in the ISO's Master File. Owners that wish to avoid risk can do so as long as they are willing to abide by the same ramp rate when selling Ancillary Services into the ISO markets.[18] Conversely, a unit owner that wants to sell more Ancillary Services should be willing to accept the risk of forfeiting Minimum Load Costs if the unit cannot ramp back to minimum load as quickly as the Owner says it can ramp up.

Powerex asserts that Minimum Load Costs should not be allocated to NNUD where the NNUD results from a curtailment beyond the Scheduling Coordinator's control. Powerex notes that the ISO expressly exempted System Resources from Uninstructed Deviation Penalties for factors beyond the System Resources' Control by revising Section 11.2.4.1.2 (b)(ii) in Amendment No. 54, and requests the ISO to provide the same express exemption from NNUD.

Section 15 of the ISO Tariff excuses Market Participants from fulfilling any obligation under the Tariff if prevented from doing so by an Uncontrollable Force. An Uncontrollable Force would include any cause beyond the reasonable control of the Market Participant which could not be avoided through the exercise of Good Utility Practice. In particular, curtailments are listed as an uncontrollable force under Section 15. Although the ISO does not believe that the specific exemption requested by Powerex is necessary given the applicable general

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[18] The ramp rate is used to validate Ancillary Service bids to ensure that the unit can provide the capacity it sells within the specified period of time.

exemption in Section 15, the ISO does not object to making the requested revision if the Commission finds it to be appropriate.

Powerex also notes that the ISO has not complied with the Commission's directive to "file either proposed tariff language incorporating Powerex'[s] request [to include System Resources in the list of resources that are subject to *force majeure* exemption from UDP], or an explanation of why such a change would be inappropriate."[19] Powerex at 10-11. In Amendment No. 54, filed on July 8, 2003 in Docket ER03-1046, the ISO filed the exemption in Section 11.2.4.1.2 (b)(ii) mentioned that exempts non-dynamically schedule System Resources from UDP that result from a curtailment of transmission capacity or to prevent curtailment of firm load. While this exemption was filed in the Docket in which the ISO submitted the Tariff provisions implementing Uninstructed Deviation Penalties, and not in Docket No. ER02-1656, the exemption filed by the ISO is the exemption that Powerex was seeking.

K. Compensation

1. Revised Gas Index Formula

While WCP/Williams generally support the ISO's proposal to revise the gas cost formula used to determine Minimum Load Costs, WCP/Williams assert the ISO failed to file amended Tariff language that would revise the gas cost formula. WCP/Williams at 6. The ISO filed appropriate changes to Sections 2.5.23.3.7.6 (Start-Up Fuel Costs) and 5.11.6.1.2 (Minimum Load Costs) but mistakenly indicated the ISO was making changes to Section 2.5.23.3.4. The proxy gas cost set forth Section 2.5.23.3.4 is used to calculate proxy bid prices that are used when bids are not submitted for the full available capacity of a generating unit subject to the must-offer obligation. While changing the gas cost formula for determining Start-Up Fuel Cost and Minimum Load Costs was part of the must-offer stakeholder process, changing the gas cost used for the proxy bids was not. The ISO apologizes for this error.

2. Inclusion of Capacity Payment

Several parties protest the ISO's failure to pay a capacity payment for capacity committed under the must-offer obligation. IEP, while advocating the use of Short-Term Reliability Contracts, asserts that there must be a backstop capacity payment mechanism for the capacity from the unit's minimum load level to the unit's maximum output level "reserved" by the ISO through the must-offer waiver process, and suggests the capacity payment could be determined by a "reference" proxy determined by an independent entity. That proxy value must by fully compensatory and include the scarcity value of the capacity, a contribution to fixed costs, and a risk premium. To encourage LSEs to enter into bilateral contracts that will meet local reliability needs, IEP also suggests that the ISO collect an administrative fee from all resource-insufficient LSEs and allocate that fee to the must-offer capacity. IEP at 22-23.

In its transmittal letter, the ISO clearly spelled out the reasons why it did not believe that a capacity payment was appropriate for a real-time must offer obligation. Transmittal Letter at 21-24. No party opposing the ISO's position

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[19] *California Independent System Operator Corporation*, 102 FERC ¶ 61,050 at P 17

specifically rebuts the ISO's specified rationales. In particular, no party attempts to demonstrate – nor can they – that a real time must offer obligation involves a reservation of a specified amount of capacity. That is a prerequisite for any type of capacity payment. For the most part parties make generic, unsupported claims that the must offer obligation does not provide adequate compensation to suppliers. Such arguments are without merit.

The Commission has found the existing must offer compensation scheme to be just and reasonable in numerous orders issued over the past several years. The nature of the must offer obligation has not changed during that time period except to provide for a waiver opportunity for suppliers. The ISO now proposes to modify the compensation scheme for must offer generators in a manner that will provide them with increased revenues, not decreased revenues. Namely, the ISO is allowing for the recovery of additional Start-Up and Minimum Load costs, as well as the opportunity to earn A/S revenues without forfeiting Minimum Load Cost recovery. It is difficult to see how the must offer compensation scheme suddenly becomes unjust and unreasonable under these circumstances. In any event, suppliers have not offered one iota of specific cost data demonstrating that the must offer obligation compensation is not compensatory with the costs they are incurring. Accordingly, their claims must fail.

In various orders, the Commission has recognized that a capacity payment is appropriate in conjunction with a Day-Ahead must offer obligation. *See Midwest Independent Transmission Company,* 102 FERC ¶61,280 at P 96

(2003).

(2003) ("*MISO*"). In *MISO*, the Commission found that a capacity payment was appropriate in connection with an obligation to bid into a Day-Ahead market, but that it was reasonable to require generators to bid available generation into the Real Time market at a level near their marginal costs. *Id.*; *see also San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator and the California Power Exchange,* 95 FERC ¶ 61,115 at 61,355-56 (2001) (a generator that has energy available in real time should be willing to sell it at a price that covers its marginal costs because it has no place else to sell the energy). The ISO is proposing continuation of its Real Time must offer obligation; the ISO is not proposing a Day-Ahead must offer obligation. Consistent with the *MISO* order, a capacity payment is appropriate for a Day-Ahead must offer obligation not a real time must offer obligation.

As the ISO indicated in the Amendment 60 Transmittal Letter (p. 60), no specific capacity is being reserved under the ISO's real time must offer obligation. Suppliers are free to sell their capacity/energy anywhere they desire and have no obligation to schedule that capacity into the ISO in the Day-Ahead time frame. Only if suppliers have capacity available in real time are they obligated to make it available to the ISO. No capacity payment is warranted in those circumstances because no call-option type of arrangement is present.

WCP/Williams contends that the ISO's refusal to pay a capacity payment is unjust and unreasonable and urges adopting one of the following alternatives in order of preference: (1) accelerating RUC; (2) continuing to pay the Uninstructed

Imbalance Energy price for the same Energy already paid its Minimum Load Costs; (3) procuring all the needed capacity through the existing Ancillary Services markets; (4) procuring only the amount of spinning reserve required under Applicable Reliability Criteria through the existing Ancillary Services market but then paying the Spinning Reserve Market Clearing Price to all unloaded capacity operating under the must-offer obligation. WCP/Williams at 30-32.

Duke asserts that the ISO should be required to continue to pay the Uninstructed Imbalance Energy payment when Phase 1B is implemented until RUC is fully implemented. Duke at 5. Though the ISO did not propose to eliminate the Uninstructed Imbalance Energy Payment made for the exact same amount of Energy as already covered by the Minimum Load Costs in Amendment No. 60, WCP/Williams use Amendment No. 60 as an opportunity to urge the Commission to direct the ISO to continue what it did not propose to eliminate in Amendment No. 60. WCP/Williams at 26-29. While WCP/Williams strongly object to the ISO's characterization of the issue as "double payment", the ISO just as strongly objects to WCP/Williams' characterization of this issue as the ISO violating the Commission's prohibition on netting. The netting proposal the Commission rejected was the ISO's proposal to net revenues from Imbalance Energy dispatched by the ISO in one hour against Minimum Load Costs in a different hour.[20] If the Commission believes that a generating unit is entitled to be paid twice for the exact same amount of Energy, and that the ISO's reluctance to

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[20] *See* January 25, 2002 Compliance Filing in Docket No. EL00-95, *et al.* at p. 13*; San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Service Into Markets Operated*

pay twice for the very same Energy constitutes netting, the ISO requests that the Commission explicitly so define netting. If the Commission decides that a generating unit is entitled to compensation for capacity offered under the must-offer obligation, the ISO requests that the capacity compensation be explicitly defined and not haphazardly valued at the Uninstructed Imbalance Energy Price.

A generating unit operating under the must-offer obligation is entitled to bid whatever price it wants. If its bid is selected, either in merit order or out-of-merit-order, the unit is paid its bid price. If the unit's bid is selected in merit order, it will be paid the market clearing price, which will be higher than its bid price. So a unit is not precluded from earning fixed cost recovery simply because it is operating under the must-offer obligation. Moreover, a unit operating under the must-offer obligation is being paid its minimum load costs, so it can bid its true incremental cost. It does not have to recover its minimum load costs by rolling those costs into its bid price.

If a unit is not operating under the must-offer obligation, but is merely selling energy into the ISO's imbalance energy, it is paid for the amount of energy it is generating. Once. Either the unit is generating in response to an ISO dispatch instruction, in which case it currently receives the Instructed Imbalance Energy price, or it is generating without instruction, in which case it receives the Uninstructed Imbalance Energy Price. It is not paid two prices. The unit can still earn fixed cost recovery, depending on the market clearing price.

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by the California Independent System Operator Corporation and the California Power Exchange Corporation, 99 FERC ¶ 61,641 (2002).

In either case, just because the unit is operating under the must-offer obligation, it should not be entitled to two payments. As the Commission noted:

> The Commission found that revenues received by generators for sales in the imbalance energy market are intended to compensate the generators for recovery of fixed costs. [21]

Energy sold into the imbalance energy market is only paid once. It is unreasonable to think that when a unit is operating under the must-offer obligation and being paid its minimum load costs that it is simultaneously selling that very same energy into the ISO's Imbalance Energy market, and is entitled to be paid for that energy as if it was a separate transaction.

With respect to parties' claims that the ISO should implement RUC, the ISO is not proposing a RUC mechanism in this proceeding. As indicated above, the filing utility determines in the first place what proposals to file with the Commission. If the proposal is just and reasonable, the Commission must accept the proposal even if there are "better" alternatives available. The Commission has found the must offer obligation to be just and reasonable, and the ISO is proposing modifications that will make the must offer obligation even more just and reasonable. Under these circumstances, the Commission should approve the revised must offer proposal and not address a RUC mechanism that is not before the Commission in this proceeding. Further, as the ISO has already indicated, diverting limited key ISO staff resources to focus their efforts solely on implementing RUC rather than on developing and deploying the entire MD02

[21] *California Independent System Operator Corporation*, 105 FERC ¶ 61,140 at 61,759 (2003).

redesign (of which RUC is a part) will almost certainly affect the schedule for deployment of the entire redesign.

L. Moving a Unit to "Dispatchable" Minimum Load

Several parties submitted comments about the ISO's proposal regarding moving a unit to its "dispatchable" minimum load. IEP does not oppose the ISO's proposal, but requests that the ISO clarify the Amendment No. 60 language. IEP at 26. Duke contends that the Commission should reject the ISO's proposal and instead require the ISO to continue to pay the unit's bid price, out-of-sequence as needed, to move the unit from its manual minimum load to its dispatchable minimum load subject to Automatic Price Mitigation ("AMP"). Duke at 6. As noted in the Amendment No. 60 Transmittal Letter, the Commission has already approved that the ISO pay the greater of the MCP or the Minimum Load Costs to the unit for its operating level, regardless of whether that unit is operating at its manual minimum load or its dispatchable minimum load.[22] The Amendment No. 60 proposal, which would be in effect up until the time the Phase 1B modifications are put into effect, is only slightly different.

Under the Amendment No. 60 proposal, the ISO will continue to pay Minimum Load Costs up to the manual minimum load amount, and pay the greater of the MCP or the unit's costs from that level to the dispatchable minimum load. Duke's asserts that the ISO should pay the unit as-bid for this quantity of energy to help recover the unit's fixed costs. Until Phase 1B is put into effect, the

[22] ISO Tariff Sections Section 5.11.6.1.1 and 5.11.6.1.2; California Independent System Operator Corp., 105 FERC ¶ 61,091 at PP 101-104.

unit will already be receiving a substantial payment towards its fixed costs through the Uninstructed Imbalance Energy ("UIE") payment, which is paid in addition to the Minimum Load Costs. The ISO's proposal to pay the greater of MCP or cost when dispatching a unit to its dispatchable minimum load may also provide some fixed cost recovery. There is no reason, however, why fixed cost recovery should be paid both through the UIE payment for the Minimum Load amount and through an as-bid payment for the amount between manual Minimum Load and dispatchable minimum load.

While most parties expressed support for the ISO's proposal to adopt the RMR gas cost formula (based on daily gas prices) for use in paying Minimum Load Costs[23], EOB remained unconvinced that the daily gas price indices are free from manipulation. EOB at 4-5. As the ISO noted in Attachment D to Amendment No. 60, Commission Staff has issued a conditional recommendation that the three gas indices the ISO would use under its Amendment No. 60 proposal be deemed to be in compliance with the Commission's July 2003 Policy Statement on Natural Gas and Electric Price Indices. Amendment No. 60 Attachment D at 4.

Mirant asserts that the proxy cost used to calculate Minimum Load Costs should address penalties related to Operational Flow Orders ("OFOs"). Mirant at 13. The ISO agrees that if a generating unit incurs an unavoidable penalty due to an OFO while complying with the must-offer obligation and the ISO's Dispatch

[23] The EOB also erroneously noted that the ISO would use daily gas costs to determine proxy bid prices. The ISO did not propose to apply the RMR gas cost formula to proxy bids. *See* discussion, *infra*.

Instructions, the generating unit should be compensated for the OFO penalties. While the ISO has the information to determine the proxy gas cost, it does not have information on the amounts of OFO penalties. The ISO therefore proposes that generating unit owners should (1) invoice the ISO for any OFO penalties occurred and (2) provide written documentation indicating how the OFO penalties were unavoidable.

M. Rescinding MLCC for Providing Ancillary Service

Parties are divided over the ISO's proposal to pay Minimum Load Costs when a unit provides Ancillary Services. The CPUC opposes this practice because this could lead to consumers overpaying to resolve the problem of bid insufficiency. Specifically, the CPUC notes that if the Ancillary Services market clearing price is set by a unit that is not being paid its minimum load costs (but may be recovering its minimum load costs and start-up costs through its Ancillary Services bid) the unit that is being paid its Minimum Load Costs and also earning the Ancillary Services MCP is effectively being double paid for its start-up and minimum load costs. CPUC at 4.

Units that have requested waivers have historically been uneconomic to run under existing market conditions. The ISO performed an empirical analysis of the decision for a waiver-denial unit to offer Ancillary Services and found that, under existing market conditions, in nearly all (historical) cases market revenues (for energy and capacity) were not sufficient to cover variable operating costs over a unit's daily run cycle. The ISO has committed units under the must-offer obligation based on system requirements for energy and on-line capacity, not on

Ancillary Service requirements or bid sufficiency. The start-up and minimum load compensation are paid expressly to make these units whole for being committed by the ISO and continuing to operate at minimum load. The payments made to units denied a waiver are not made for a specific amount of capacity provided, either as Ancillary Services or unloaded online capacity, nor are they made for the provision of energy in response to dispatch instructions in real-time.

Historically, units denied a waiver have not bid into the Ancillary Service markets. Given this, there has been little or no 'savings' associated with rescission of payments when a waiver-denial unit has sold Ancillary Services to the ISO. Furthermore, units have not been 'paid twice' for their start-up and minimum load because they have not historically chosen capacity payments over commitment payments and consequently have not sold Ancillary Services to the ISO. This also means that capacity from these units has been unavailable to the Ancillary Services markets because of the payment rescission.

Eliminating the rescission of commitment payments when waiver-denial units sell Ancillary Services to the ISO will not increase outlays for these payments since the ISO will commit the same amount of capacity with or without rescission. Furthermore, since units have historically chosen commitment payments over capacity payments there are no true savings in rescinded commitment payments that will be lost with non-rescission. The only anticipated change will be increased capacity offered in the Day-Ahead Ancillary Service Markets.

Because the Ancillary Service markets operate as a single-price auction, all lower-priced bids will receive a premium over their bid price when the MCP is set by a higher-priced bid. This is true either with or without rescission of start-up and minimum load compensation. That waiver-denial units may receive a premium over their bid price, or be 'double-paid' as the CPUC suggests, is immaterial since all selected bids priced below the price-setting bid in a Service will receive such a premium as a function of the single-price auction. In this context, rescission of the unit commitment compensation when a waiver-denial unit sells Ancillary Services to the ISO will subject this unit to start-up and minimum load costs that were capitalized into the capacity bid from non-waiver-denial unit. This approach will not guarantee the unit is made whole for being committed by the ISO.

The ISO believes that continued rescission of the commitment compensation (1) will serve to force the same preference for commitment compensation over capacity payments resulting in un-bid Ancillary Service capacity, (2) is not likely to result in any savings in commitment compensation, and (3) will subject waiver-denial units that do choose to sell Ancillary Services to the ISO to commitment compensation bid by another unit.

SMUD also opposes the proposal because the ISO has not examined the cost impacts of the proposal and because paying Minimum Load Costs creates an incentive for suppliers to not participate in other ISO markets where they could earn fixed cost recovery. SMUD at 7-8.

The Must Offer Obligation requires units to participate in the Imbalance Energy market. Payment of minimum load costs does not directly impact this participation and analysis performed by the ISO indicates that, historically, units requesting a waiver are typically uneconomic to self-commit (market revenues would not have covered variable operating costs under existing market conditions) and would therefore not have been on-line and able to participate in the imbalance energy market if not obligated to do so. The same uneconomic conditions would have prevented these units from participating in the Ancillary Service markets. Participation in the Ancillary Service markets by waiver-denial units has been retarded by the rescission of start-up and minimum load costs. The proposed Amendment No. 60 recognizes this and proposes elimination of payment rescission to eliminate the disincentive for waiver-denial units to participate in the Ancillary Service markets.

Powerex opposes the proposal because it believes the Ancillary Services bids from generating units whose Minimum Load Costs are paid will be lower than other units that must recover those Minimum Load Costs through their bids, depressing Ancillary Services prices. Powerex at 8. PG&E expects Ancillary Services Costs to increase if the ISO's proposal is accepted and opposes paying Minimum Load Costs to a unit providing Ancillary Services at least until the Uninstructed Imbalance Energy payment is eliminated in Phase 1B. PG&E at 8.

The ISO notes that it is unreasonable to expect Ancillary Service costs to increase when elimination of payment rescission is expected to increase capacity measurably offers into the Ancillary Service markets and increase competition.

The ISO's comments on payment of UIE are discussed in another section of this response.

Other parties support the ISO's proposal. *See* Duke at 1; EOB at 5; WCP/Williams at 33.

N. MSS

The City of Santa Clara, doing business as Silicon Valley Power ("SVP"), has an Metered Subsystem ("MSS") Agreement with the ISO. SVP raises some concerns with Amendment No. 60.

First, SVP requests that the Commission direct that the Commission order that the ISO's assumption that, with regards to an MSS, a unit that submits Day-Ahead Energy Schedules will be on-line and operating the next day, is not appropriate, because an MSS Operator is not bound to those schedules but can follow its own Demand. SVP at P 22.

Second, SVP finds that the ISO's assumption that the amount of municipal generation committed through forward schedules might conflict with the rights an MSS Operator enjoys under the MSS Agreement. SVP at P 23.

Third, SVP questions whether the ISO intend that MSS Operators submit waiver requests when following their own Demand. SVP at P 24.

The ISO holds that MSS Operators, including SVP, are exempt from the must-offer obligation. As SVP acknowledges, SVP's concerns are moot if SVP resources are not subject to the must-offer obligation. SVP at 12-13 footnote 15.

O. Self-Commitment

Several parties reject the ISO's clarification that if a unit submits Day-Ahead energy schedules, then revokes those schedules and seeks a waiver, that the ISO should not have to pay the unit's Minimum Load Costs if the ISO still requires that unit that had indicated it would be on in the Day-Ahead time frame to remain in operation. Duke at 4-5. Mirant at 4-5. WCP/Williams at 19-25. The ISO discussed its clarification at length in the Amendment No. 60 transmittal letter and believes it has addressed the relevant issues therein. Amendment No. 60 transmittal letter at 17-20. The Amendment No. 60 proposal benefits suppliers by allowing the ISO to grant a waiver for a unit self-committed in the Day-Ahead time frame, where before the unit owner could not request nor the ISO grant such a waiver.

P. RMR Condition 2 Issues

Based on comments from intervenors, it would appear that some parties believe that the ISO has no authority to dispatch of Condition 2 RMR Units out-of-market ("OOM"). This is not the case. The ISO has existing authority under Section 5.6.1 of the ISO Tariff to issue an OOM dispatch to "**all** Generating Units… that are owned or controlled by a Participating Generator…during a System Emergency and in circumstances in which the ISO considers that a System Emergency is imminent or threatened. There is no specified exemption for RMR Condition 2 Units nor should there be. RMR Condition 2 Units are Generating Units owned/controlled by a Participating Generator and are subject to Participating Generator Agreements. Because Section 5.6.1 applies to **all** PGA units, RMR Condition 2 Units necessarily must be subject to the provisions of Section 5.6.1. In any event it is an absurd proposition, that in cases of System Emergency, the ISO would not be able to call on **all** units subject to PGAs to resolve the emergency. A RMR Condition 2 contract does not relieve unit owners of their responsibilities under the PGA they have executed with the ISO.[24] The purpose of the proposed tariff amendment dealing with Condition 2 RMR Units is threefold: (1) to allow the ISO to dispatch Condition 2 units for non-local reliability needs when non-RMR Units are not available before conditions reach a critical stage; (2) to offer OOM variable-cost compensation to Condition 2 RMR Units that is more consistent with the cost compensation provided for in the RMR Agreement than the OOM compensation currently provided for in the Tariff; and (3) to allocate costs for non-local reliability dispatches more broadly to the market. There is no sound legal or policy basis for not allowing the ISO to dispatch Condition 2 RMR Units for reliability purposes when other Generating Units are not available. These units recover 100% of their fixed costs from the ISO and the Responsible Utility and if they are physically capable of providing energy, the ISO should be able to call upon them to do so. The ISO should not be required to wait until there is an emergency.

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[24] As explained in the May 11, 2004 transmittal letter, the RMR Agreement prohibits RMR Condition 2 Units from participating in the market unless subject to an ISO Dispatch Order. Under the RMR Agreement, the ISO can only dispatch an RMR Unit to meet local reliability needs or to resolve intra-zonal congestion The RMR Contract defines Market Transactions as “a delivery of Energy or provision of Ancillary Services from a Unit pursuant to a Direct Contract of bids into markets run by the PX, ISO or any similar entity.” By definition, an OOM call is not a Market Transaction and does not conflict with the RMR Agreement. Further, an OOM call does not involve a Direct Contract between the unit owner and an identified person or persons for the sale of Energy or Ancillary Services.

Comments from intervenors regarding this issue run the gamut.[25] Several parties protest the ISO's proposal regarding the use of Condition 2 RMR Units outside of the RMR Contract. Calpine at 3. IEP at 24. Mirant at 9-13. WCP/Williams at 38-46.

Mirant urges the Commission to direct the ISO to modify its tariff to implement the "compromise" solution for use of Condition 2 RMR units emanating from the September 3, 2003 technical conference. Mirant at 13. The Commission should reject this suggestion. While the parties at that technical conference discussed some principles that might form the basis of a compromise, and made some effort to negotiate a temporary "patch" that would allow the ISO to use Condition 2 RMR units until the issue could be pursued further with the Commission, the parties could not arrive at an agreement on the terms of that "patch" solution. A major sticking point in those discussions was Mirant's unwillingness to file this "patch" with the Commission and be bound by the Commission's subsequent action. Moreover, despite Mirant's representations in its protest that the ISO would have to declare an emergency, the language developed in the "patch" expressly indicated that the ISO would NOT have to declare an emergency before using Condition 2 RMR units for non-RMR purposes.

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[25] PG&E supports "[s]etting forth clear conditions under which Condition 2 RMR units are subject to the Must Offer Obligation." PG&E at 5. While the ISO appreciates PG&E's support, the ISO notes that the sentence PG&E quotes from the first page of the transmittal letter is an inaccurate relic mistakenly left over from an earlier draft of the transmittal letter when the ISO was advancing a proposal that would make Condition 2 units subject to the must-offer obligation. The ISO later dropped that proposal for reasons described beginning on page 39 of the Amendment No. 60 Transmittal Letter.

WCP/Williams urges the Commission to reject the ISO's proposal for using Condition 2 RMR Units. Should the Commission adopt the ISO's approach, WCP/Williams recommends the following: (1) The ISO should set the market clearing price to the damage control bid cap level (currently $250/MWh) so that the market reflects scarcity and opportunity costs whenever the ISO calls on non-RMR service from an Condition 2 RMR unit; (2) in the alternative, the market clearing price should reflect the higher of the last accepted market resource or the Schedule G rate of the Condition 2 RMR unit; (3) that the ISO be required to declare an emergency prior to calling on non-RMR service from the Condition 2 RMR unit; (4) require an independent market monitor – not the ISO's Department of Market Analysis, which WCP/Williams believes is not independent because it is subject to the ISO Board – to examine, in each quarter in which the ISO dispatches Condition 2 RMR units, whether the ISO has "reasonably used all other available and effective resources" before calling on a Condition 2 RMR Unit to provide non-RMR service and why market bids were not sufficient at the time the Condition 2 RMR Unit was called on; (5) expressly define what "effective" means (WCP/Williams suggests that a unit is effective when it has a ten percent effectiveness factor (a 0.1 MW effect on the constraint for every MW dispatched from the unit)); (6) Condition 2 RMR Units should always be paid Schedule G rates to discourage the ISO from calling on the units and to compensate the unit for increased run times; and (7) the ISO must be prohibited from calling on a Condition 2 RMR unit if doing so would cause it to exceed environmental limits. WCP/Williams at 43-46. The Commission should reject these conditions.

Condition 2 RMR Units should remain outside the market and not influence prices in the ISO's markets. The ISO proposed a pricing mechanism that it believes is fully compensatory. The ISO agrees that Condition 2 RMR Units should recover their incremental costs for any incremental service. Schedule G compensation would represent a windfall and discourage Units from transferring to Condition 1. Finally, all units subject to a PGA are entitled to decline an ISO Dispatch if complying with the Dispatch would violate the law. *See* ISO Tariff Section 20.8.

WCP/Williams also contends that relying on Condition 2 RMR Units for system needs will create incentives to delay the full implementation of resource adequacy. WCP/Williams at 39. Although resource adequacy could eliminate the need for RMR contracts entirely — an outcome the ISO would welcome— neither the ISO nor the FERC should hold reliability in the here and now hostage to resource adequacy in the future.

WCP/Williams asserts that Condition 2 RMR Contract permits those units to provide Energy only when issued a Dispatch Notice and that this restriction was negotiated between the Investor Owned Utilities and the ISO, not with the current RMR Owners. WCP/Williams at 42 (footnote 92). WCP/Williams' carefully crafted description of the limitations on providing energy under the Condition 2 RMR Contract obscures the fact that the RMR Contract **requires** that a Condition 2 RMR Unit bid into the ISO's Imbalance Energy and Ancillary Services markets once it is dispatched under the RMR Contract.[26] The Contract

[26] The one exception to this requirement is the Hunters Point facility, which is prohibited from bidding into the ISO's markets in accordance with an agreement between PG&E and the City of San Francisco.

expressly contemplates that a Condition 2 RMR Unit will provide energy for non-local reliability needs once it is dispatched for local reliability (or intra-zonal) needs. This bidding requirement was included to ensure that a Condition 2 RMR Unit could not exercise market power through physical or economic withholding.

Finally, WCP/Williams asserts that this limitation was intended to ensure that reliability service was preserved for the Responsible Utility paying the full fixed costs under the RMR Contract. WCP/Williams at 42. This is factually inaccurate and nonsensical. First, because the RMR Contract already authorizes the ISO to direct the RMR Owner to not bid into the ISO's markets if the ISO believes that any market energy provided in excess of the local reliability requirements would jeopardize the unit's ability to provide RMR service later in the year.[27]

Second, while the initial drafts of the RMR Contract were developed by the Investor Owned Utilities ("IOUs"), and then between the IOUs and the ISO, by the time the April 2, 1999 partial settlement of RMR issues was reached the current RMR Owners were ably represented in the settlement and contract negotiations, as the companies listed in the Stipulation and Agreement memorializing that settlement will attest.

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[27] Section 6.1 (b) of the RMR Contract states "ISO may order Owner not to bid to participate in a Market Transaction if ISO determines that participation in Market Transaction would cause a Unit to exceed Contract Service Limits or impair ISO's ability to dispatch the Unit to meet reliability needs at other times during the Contract Year."

Duke requests that the Commission direct the ISO to clarify whether "reasonable efforts" to use all available and effective non-Condition 2 units means that the ISO will have revoked the must-offer waiver of an effective non-Condition 2 RMR Unit. In general, the answer is yes – reasonable efforts would require the ISO to revoke the waiver of an effective non-Condition 2 RMR Unit. It is possible that there may be special circumstances – e.g., that the non-Condition 2 RMR unit may be effective and have a positive effect on one reliability problem, while it may have a detrimental effect on a different reliability problem – that would cause the ISO not to revoke the waiver of the effective non-Condition 2 RMR Unit the ISO generally expects that "reasonable efforts" would include revoking the waivers of effective non-Condition 2 RMR Units.

On the other hand, the EOB supports the ISO's proposal for use of Condition 2 RMR units outside the RMR Contract with three caveats. First, the EOB asserts that non-RMR service should not be used to determine future RMR Contract service limits to discourage the ISO from overusing the Condition 2 RMR units. EOB at 6. Under the current RMR Contract, all service – both RMR and non-RMR – is used to determine future years' service limits. The ISO is not proposing to change this provision of the RMR Contract. Second, the EOB directs that the ISO establish a hierarchy of units to be called on prior to calling on Condition 2 RMR units. *Id*. To do so would require the ISO to forecast the conditions under which it would require the non-RMR use of a Condition 2 unit. In general, the need to use a Condition 2 RMR Unit for non-RMR service arises due to temporary circumstances and cannot easily be predicted. Finally, the

EOB contends that charges for the non-RMR use of Condition 2 RMR Units should be assigned on a cost-causation basis, and not to the Participating TO responsible for charges under the RMR Contract. The ISO agrees that charges for non-RMR service should not be allocated to the Participating TO, and has proposed that any start-up cost associated with non-RMR use of a Condition 2 RMR Unit be allocated in the same way Start-Up Costs for must-offer units are allocated – to metered Demand and export. The ISO has also proposed that energy costs for calling on non-RMR service from a Condition 2 RMR unit be allocated the same way OOM Energy charges are currently allocated. *See* ISO Tariff Section 11.2.4.2.1.

Q. Issues for Compliance Filing

In addition to the correction described in Section II(K)(1) of this Answer, the ISO has noticed certain typographical errors in the tariff language filed with Amendment 60, and one of these errors is significant.

In Attachment A2 of the Amendment 60 filing, which constitutes "clean" tariff sheets as effective when Amendment No. 54 has gone into effect, there is a typographical error in Equation 1b on Original Sheet No. 249A. The proper form of the equation, as noted in the blacklined tariff sheets provided in the Amendment 60 filing, is as follows:

$$\frac{A * (B + CX + De^{FX}) * P * E}{X} \qquad + \text{Variable O\&M Rate}$$

As with the correction described in Section II(I)(8) above, the ISO proposes to correct this equation, together with some less significant typographical errors, in a compliance filing.

III. CONCLUSION

Wherefore, for the foregoing reasons, the ISO respectfully requests that the Commission accept Amendment No. 60 in its entirety, except for the limited modifications noted herein.

Respectfully submitted,

_/s/ ***Anthony J. Ivancovich***__
Charles F. Robinson
General Counsel
Anthony J. Ivancovich
Senior Regulatory Counsel
The California Independent System
Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630
Tel: (916) 608-7049
Fax: (916) 608-7296

_/s/ ***Julia Moore***___________
David B. Rubin
Julia Moore
Swidler Berlin Shereff Friedman, LLP
3000 K Street, Suite 300
Washington, DC 20007
Tel: (202) 424-7500
Fax: (202) 424-7643

Date: June 16, 2004

CERTIFICATE OF SERVICE

I hereby certify I have this day served the foregoing document on each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Folsom, CA, on this 16th day of June, 2004.

_/s/ ***Anthony J. Ivancovich***___
Anthony J. Ivancovich

California Independent
System Operator

June 16, 2004

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

Re: California Independent System Operator Corporation
Docket No. ER04-835-___

Dear Secretary Salas:

Enclosed for electronic filing, please find a Motion for Leave to File Answer and Answer of The California Independent System Operator Corporation to Motions To Intervene, Comments, and Protests

Thank you for your assistance in this matter.

Respectfully submitted,

/s Anthony J. Ivancovich
Anthony J. Ivancovich

Counsel for the California Independent
System Operator Corporation