**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

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| **California Independent System Operator Corporation** | ) ) | **Docket No. ER04-609-___** |

**REQUEST FOR REHEARING OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION**

Pursuant to Rule 713 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713, and Section 313(a) of the Federal Power Act, 16 U.S.C. § 825l (a), the California Independent System Operator Corporation ("CAISO")[1] hereby requests that the Commission grant rehearing of its "Order on Amendment No. 58" issued on August 5, 2004 in the captioned proceeding ("August 5 Order").[2] As explained below, the ISO is requesting that the Commission delay acting on one element of this Request for Rehearing.

In support of this request, the CAISO respectfully states as follows:

## I. BACKGROUND

On July 8, 2003, the ISO submitted Amendment No. 54 to the ISO Tariff ("Amendment No. 54"). Amendment No. 54 was intended to provide details for the implementation of certain of the market redesign elements initially proposed in the May 1, 2002 filing (the Phase 1B redesigns). In particular, Amendment No. 54

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

2 *California Independent System Operator Corporation*, 108 FERC ¶ 61,141 (2004).

proposed to use one set of ramp rate values to dispatch and settle both Reliability Must-Run ("RMR") and market transactions by allowing owners of RMR Units to modify Schedule A of their RMR Contracts to indicate that ramp rates that would be used for RMR transactions would be those ramp rates that a Scheduling Coordinator may bid into the ISO's Imbalance Real-Time Energy market each day (and that they may change closer to real-time through the Scheduling Logging for the ISO of California ("SLIC") web client). Should an Owner not take advantage of this opportunity, the ISO proposed that the RMR Contract ramp rates would be used to settle the market transactions. The Commission approved this proposal in its October 22, 2003 order on Amendment No. 54, *California Independent System Operator Corporation*, 105 FERC ¶ 61, 091 (2003) ("Amendment No. 54 Order") at P 23.

On March 2, 2004, the ISO filed Amendment No. 58 to the ISO Tariff. In Amendment No. 58, the ISO proposed to extend the treatment approved for ramp rates in Amendment No. 54 to two other operating characteristics – minimum operating level (Pmin) and start-up lead time. On August 5, 2004, the Commission issued the Amendment No. 58 Order, rejecting the ISO's proposal to extend this proposed treatment.

## II. SPECIFICATIONS OF ERROR

### A. RMR and Market Values

The Commission erred in rejecting the ISO's proposal (1) to allow an RMR Owner to modify its RMR Contract Schedule A to use the Pmin and start-up lead time bid into the ISO's markets to settle both market and RMR transactions, or (2) to settle both RMR and market transactions using the RMR Contract Schedule A Pmin and start-up lead time values.

### B. Bid Cost Recovery

The Commission erred in rejecting the ISO's proposal to eliminate Bid Cost Recovery payments to resources operating outside the Dispatch Operating Point tolerance band outside of Waiver Denial Periods.

## III. REQUEST FOR REHEARING

### A. RMR and Market Values

#### 1. <u>The ISO Did Not Propose To Require Only One Unchanging Set Of Values For Both Market and RMR Transactions</u>

The Commission rejected the ISO's proposal as follows:

> We will reject the CAISO's proposal requiring RMR generators to use only one set of values for minimum operating level and start-up lead time. We find convincing Calpine's argument that it is reasonable for an RMR generator to have one set of values in its RMR contract that is achievable on a year-round basis and another set for use in market transactions. Requiring an RMR owner to use the same values will limit the owner's ability to enter into market transactions or will compel the owner to assume the risk that it can operate at maximum values when called upon by the ISO. The CAISO's argument that ***one set of values*** is administratively convenient and will reduce the likelihood of errors and disputes is not a compelling reason to limit a RMR generator's flexibility. We therefore direct the CAISO to retain the *status quo* and permit different values for minimum load and start-up lead time as set out in Schedule A of the RMR contract and in the CAISO's Master File.

Amendment No. 58 Order at P 22 (emphasis added). The Commission appears to view the ISO's proposal as a requirement for the RMR Owner to use "one set of values" on a permanent basis. This is incorrect. Although the ISO's proposal was to use the same value for both RMR and market transactions, the RMR Owner would be free to change these values for both the RMR contract and for market transactions on a daily basis.

Accordingly, the ISO did not propose that the Owner had to specify a single, unchanging set of market values for Pmin and the start-up lead time that also would be used to settle its RMR transactions.

The operational characteristics for a unit may change over the course of an annual RMR Contract. If an RMR Owner is to be held responsible to a single set of unchanging values for the performance of its RMR Unit over the course of a year, it is perfectly rational for an RMR Owner to specify conservative values in its RMR Contract. This would ensure that the RMR Unit always could meet those values over the course of the year.

On any given day, however, the operating characteristics of a unit typically do not change appreciably across that day. On that given day, the RMR Unit may respond to RMR dispatch instructions as well as market dispatch instructions. On that day, the RMR Unit should not physically respond any differently to a request to start-up that is issued under the RMR Contract from how it responds to a request to start-up issued through the ISO's markets. On that day, the unit is capable of operating at a particular Pmin regardless of whether instructed under the RMR Contract or through the ISO's markets. The Scheduling Coordinator for the RMR Owner can indicate to the ISO through its bids what the Unit's Pmin and start-up lead time is for that day.

The ISO proposed to allow the RMR Owner to modify the start-up lead time and Pmin in Schedule A to its RMR Contract to indicate that the values used to dispatch and settle that RMR Unit for any given day will be the same values bid into the ISO's markets. These values can and should reflect the physical capability of the unit on a given day. Moreover, should the need arise, the Scheduling Coordinator could change these values after they have been bid in through the SLIC web client. If the daily bids reflect the actual capability of the RMR Unit, the RMR Unit likely will never be dispatched beyond its physical capability under the RMR Contract. The Real-Time Market Application ("RTMA") will not dispatch a Generating Unit below the Generating Unit's economic minimum operating levels submitted in bids unless the ISO faces Overgeneration.[3] The RMR Owner's Scheduling Coordinator, however, also may submit a revised minimum operating level to the ISO via the SLIC web client that RTMA would not violate under any condition. Thus, through bidding and notice to the ISO, the operating values at issue in this proceeding could be managed so that there would be little to no risk for the RMR Owner.

If the RMR Owner would not modify its RMR Contract Schedule A to use its bid-in market values, the ISO proposed to use the RMR Contract value to settle both market and RMR transactions. The ISO had hoped that every RMR Owner would elect to modify its Schedule A so that the RMR Contract values would never have to be used as the default values for market transactions. Because the ISO benefits from using the same value to settle RMR and market transactions in any interval, the ISO proposed to use the RMR Contract values for both market and RMR transactions if the Owner did not so modify its Schedule A, and thus create an incentive for the Owner to modify its Schedule A.

[3] Under normal circumstances, the RTMA will not dispatch a Generating Unit below the Pmin specified in the Generating Unit's bids, even if that bid-in Pmin is greater than the value specified in the Master File. It is possible, however, that RTMA would dispatch the unit to its Master File Pmin under emergency conditions, such as during Overgeneration.

2. <u>Having Two Different Operating Values In Any Interval Will Needlessly Complicate Uninstructed Deviation Penalties</u>

The RTMA, slated to go into service on October 1, 2004, should not be required to be designed to accommodate two sets of operational values. When an RMR Unit is dispatched under the RMR Contract, the RMR Dispatch Instruction will be sent out through the RMR client or telephone call and will be based on the RMR Contract values. RTMA, however, will dispatch the unit through the ISO's Automated Dispatch System ("ADS") and calculate the unit's Expected Energy based on the unit's Master File values, not on the RMR Contract values. If the RMR values are significantly different than the Master File values, the difference in the Expected Energy values could be significant. If the unit were to operate at the level dispatched under ADS it could operate at levels for which it would not be fully compensated under the RMR contract. Alternatively, if it were to operate in accordance with the RMR dispatch instruction, the difference between the Energy produced at its RMR operational level and the Expected Energy calculated by RTMA could appear as a deviation that would be subject to Uninstructed Deviation Penalties ("UDP"). Consider these examples:

**<u>Example 1</u>**:

Master File minimum operating level (Pmin) = 75 MW

RMR Contract minimum operating level = 50 MW

If the unit were dispatched at its RMR contract minimum operating level for an hour under the RMR Contract, the unit would produce 50 MWh of Energy. RTMA, however, cannot calculate a dispatch trajectory at values less than the 75 MW minimum operating level listed in the Master File and, as such, would calculate 75 MWh of Expected Energy. If the unit delivered 50 MWh of Energy, as requested under the RMR dispatch, the unit would be subject to the UDP for 25 MWh of apparently under-delivered Energy. Alternatively, if the unit operated at 75 MW, it would not be compensated under the RMR contract for the additional 25 MWh of Energy.

**<u>Example 2</u>**:

Master File minimum operating level (Pmin) = 50 MW

RMR Contract minimum operating level = 75 MW

When the opposite situation from Example 1 exists, that is, the RMR Contract minimum operating level is greater than the minimum operating level listed in the Master File, RTMA would calculate Expected Energy for the unit once it had reached its minimum operating level listed in the Master File. For settlement purposes under the RMR Contract, however, the RMR Unit still would be operating in start-up mode until it reached the minimum operating level specified in its RMR Contract. As a result, the unit may deviate from the ramp trajectory calculated by RTMA, resulting in a different Expected Energy and the application of UDP. This deviation would not be fully addressed by the effective UDP suspension for start-up proposed by the ISO in ISO Tariff Amendment No. 62, as the UDP suspension's duration ends once the unit reaches the minimum operating level listed in the Master File and only applies to positive Uninstructed Imbalance Energy.

**<u>Example 3</u>**:

Similar to the situation that would exist for a difference between the minimum operating level in the RMR contract and that listed in the ISO's Master File, differences between the start-up lead times in the RMR Contract and the ISO Master File would also result in significant differences in Expected Energy.

Master File start-up time = 20 minutes

RMR Contract start-up time = 30 minutes

Master File and RMR minimum operating level = 75 MW

RMR dispatch = 100 MW

If the unit were dispatched to start-up using its RMR Contract start-up time, the unit would reach its 75 MW minimum operating level in 30 minutes. RTMA, however, would utilize the 20-minute start-up time listed in the Master File and would calculate that the unit would reach its 75 MW minimum operating level in 20 minutes, rather than in 30 minutes. After 20 minutes, RTMA would then dispatch the unit to ramp up to the 100 MW operating level desired under the RMR dispatch instruction, while the unit would actually still be in the process of ramping up to its minimum operating level.

This situation would result in significant differences in Expected Energy between what would be dispatched under the RMR Contract and what would be calculated by RTMA, resulting in the RMR Unit incurring negative Uninstructed Imbalance Energy that would be subject to UDP. The effective UDP suspension proposed by the ISO in Amendment No. 62 would not address this situation because the proposed effective UDP suspension applies to positive Uninstructed Imbalance Energy, not negative Uninstructed Imbalance Energy. Additionally, the differences in Expected Energy would exist after the maximum start-up time listed in the Master File, which is the end of the time period for which the effective UDP suspension proposed in Amendment No. 62 applies.

3. <u>It is Not Possible to Comply with the Commission's Directive In Time To Permit Phase 1B to Become Operational On October 1, As Scheduled</u>

As described in the ISO's filing in compliance with the Order on Amendment No. 58, being filed concurrently with this Request for Rehearing, the ISO systems cannot be re-coded to be able to use two sets of values depending on whether the dispatch is issued under the RMR Contract or through the market prior to the Phase 1B scheduled implementation date of October 1, 2004. The ISO expects it will take up to six months to re-code the RTMA so it can store two sets of different operating characteristics and use different values to calculate the Expected Energy based on whether the instruction is issued under the RMR Contract or through the market.

4. <u>Alternative Proposal To Satisfy Commission's Directive and Achieve October 1 Implementation</u>

To accommodate the Commission's direction to allow two sets of operating values and prevent a unit from incurring UDP, the ISO would need to implement the following procedure:

Where an RMR Unit had different minimum operating level values in the Master File and the RMR Contract, the Scheduling Coordinator for the RMR Unit would establish the lesser value in the Master File.

Using the SLIC web client, the Scheduling Coordinator for the RMR Unit would then be able to change the unit's minimum operating level to higher values than that established in the Master File. This would allow the Scheduling Coordinator the flexibility to change the minimum operating level as conditions change with time and to respond to market opportunities for which a different minimum operating level than that used for RMR operations may be appropriate. This would ensure that RTMA will calculate Expected Energy for either an RMR dispatch or a Market dispatch correctly and would address the issues described in Examples 1 and 2, above.

Similarly, where the start-up lead time specified in the RMR Contract is different than that specified in the Master File, the Scheduling Coordinator for the RMR Unit would specify the longer of the two start-up lead times (presumed to be from the RMR Contract) in the Master File. This value would be used for both RMR and market transactions.

If the owner of the RMR Unit wanted to use the shorter market time for a market transaction, the RMR Unit would be permitted to bid in a shorter start-up lead time for use in the market.

The Expected Energy for the start-up will be calculated using the appropriate start-up lead time, addressing the issue discussed in Example 3. As start-up lead times for market transactions are submitted one hour prior to the operating hour, however, the possibility exists that an RMR dispatch instruction could be issued in an hour for which the owner had submitted a shorter market start-up lead time, in which case the issue described in Example 3 would still exist. This situation would be resolved if the owner of the RMR Unit agreed to use any shorter start-up time that had been bid in for the applicable operating hour.

While the ISO believes that the procedures proposed in Amendment No. 58 still represent the best approach for dealing with this issue, the alternative approach would allow the ISO to implement RTMA on October 1.

5. Discussions with Calpine

The ISO has discussed the proposed alternative process with Calpine, the only ISO Market Participant that protested this element of Amendment No. 58. The results of these discussions are an agreement between the ISO and Calpine that the proposed alternative process will go into effect for a six-month trial period, during which time the ISO requests that the Commission not act on this element of its Request for Rehearing. For the six-month trial period, Calpine has expressed a willingness voluntarily to change its RMR Contract Schedule A to specify that the start-up lead time value to be used for RMR dispatch would be the same as that bid into the market for use in the market. This is the proposal the ISO had made in Amendment No. 58 – to allow an RMR Owner to specify in its RMR Contract that RMR and market transactions will both use the operating characteristics that the RMR Owner's Scheduling Coordinator bids into the ISO's market.

6. Request for Delayed Action

The ISO requests that, during the six-month trial period, the Commission take no action on this element of the Request for Rehearing, other than issuance of a tolling order.[4] During the six-month trial period, as proposed by the ISO and Calpine, the ISO shall have no obligation to commence any work related to implementing software revisions that would enable the ISO to incorporate two values (for RMR and non-RMR) for minimum load and start-up lead time, or any other criterion, into its RTMA systems. At the end of the six-month trial period, if the alternative procedures set forth above work to the ISO's and Calpine's satisfaction, the ISO would put these procedures into

[4] The ISO seeks no such delay for the second element of this Request for Rehearing, described in Section III(B) below.

effect permanently, and the RTMA would not have to be modified. If, at the end of the six-month trial period, the procedures do not work for either the ISO or Calpine (or both), the relevant party would notify the Commission of this and the Commission would then act on the ISO's Request for Rehearing.

### B. Bid Cost Recovery

Rational Market Design Dictates That Bid Cost Recovery Be Conditioned On Operation Within The Tolerance Band

In the Order on Amendment No. 58, the Commission rejected the ISO's proposal to eliminate bid cost recovery payments for resources operating outside the Dispatch Operating Point tolerance band outside of Waiver Denial Periods. The Commission based this decision on reasoning articulated in its Order on Amendment No. 54, to the effect that mechanisms already in place, such as UDP, are "more than adequate" deterrents to generators seeking to receive compensation despite failing to perform. Order on Amendment No. 58 at P 67, quoting the Order on Amendment No. 54 at P 71.

As demonstrated below, the UDP is *not* a sufficient deterrent to such behavior. With the Bid Cost Recovery procedure as ordered by the Commission, it is quite possible for a generator to fail to respond to an instruction from the ISO and yet receive substantial compensation. The reason for this is that although the ISO settles Imbalance Energy and provides Bid Cost Recovery based on the ***instruction***, it applies UDP based on the ***delivery***. This is demonstrated in the following example:

A resource with a bid of $50/MWh is instructed to deliver 100 MW. The resource does not respond to the instruction (*i.e.*, delivers 0 MWh). The Market Clearing Price ("MCP") when the resource is instructed is $20/MWh. The resource will be paid according to the instruction: 100 MW times $20/MWh = $2,000. The deviation due to the unit's failure to respond is also charged the MCP: (100 MW) times $20/MWh = ($2,000). UDP – a 50% premium on the MCP – are applied: (100 MW) times (0.5) times $20/MWh = ($1,000). Finally, because Bid Cost Recovery is based on the ***instruction***, even though the resource failed to deliver *any* of the instructed Energy, the Bid Cost Recovery – paid based on the difference between the MCP and the unit's bid price - would amount to 100 MW times ($50/MWh - $20/MWh) = $3,000. Thus, the net settlement would be:

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| Payment for the instruction | $2,000 |
| Charge for the deviation | ($2,000) |
| UDP | ($1,000) |
| Bid Cost Recovery | $3,000 |
| Net Settlement | $2,000 |

In this scenario, the unit receives a net payment of $2,000 even though it did not generate *any* Energy in response to the ISO's instruction.

Moreover, UDP is an after-the-fact remedy that cannot achieve the same power as providing the incentives for proper generator behavior from the start. It is a cliché, but no less true for being a cliché, that an ounce of prevention is worth a pound of cure. Rather than providing an incentive for a generator to avoid following an ISO dispatch instruction and then providing a penalty that perhaps partially offsets this incentive, it would be far better not to provide the incorrect incentive at all.

If permitted to continue, providing Bid Cost Recovery for generators outside the tolerance band would be a poor market design, creating incentives for generators to fail to follow ISO dispatch instructions under some circumstances. Clearly this outcome is neither just nor reasonable, and the ISO does not believe that it is one that the Commission intended. As the Commission has recognized,

> Managerial actions that affect efficiency do not take place in a vacuum. They are influenced by our regulation and that of the state commissions. We recognize that our rules and policies can sometimes have unintended consequences that produce higher costs and higher rates. Consumers do not benefit from dysfunctional regulation.

*Public Service Company of New Mexico, et al.*, 25 FERC ¶ 61,469, 62,033 (1983) (citation omitted). By allowing generators to receive "compensation" for nothing, the Commission would be sanctioning counterproductive incentives.

## IV. CONCLUSION

WHEREFORE, for the foregoing reasons, the CAISO respectfully requests that the Commission grant the instant request for rehearing.

Respectfully Submitted,

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## 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 7th day of September, 2004.

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Brian D. Theaker