STATEMENT ON PARTIAL SETTLEMENT FILING

ERIC W. HILDEBRANDT, Ph.D.
MARKET SURVEILLIANCE UNIT
CALIFORNIA INDEPENDENT SYSTEM OPERATOR

Introduction

I am Manager of Market Monitoring Systems, with the Market Surveillance Unit (MSU) of the California Independent System Operator (ISO). I hold a B.S. degree in Economics from the Colorado College, and an M.S. and a Ph.D. in Energy Management and Policy from the University of Pennsylvania. I have specialized in economic analysis and market research relating to energy issues for over ten years, with emphasis on performing economic and market research, planning and evaluation studies for the electric utility industry. I began my career in energy research at the Center for Energy and Environment at the University of Pennsylvania, and then worked for over six years as an economic consultant to the electric utility industry with the firms of Xenergy Inc. and Hagler Bailly Consulting in Philadelphia, Pennsylvania. Prior to joining the ISO, I worked for over three years at the Sacramento Municipal Utility District as Supervisor of Monitoring and Evaluation. I have published numerous articles on energy issues in professional journals and have frequently presented my research in academic and industry forums. A list of publications and conference papers on energy issues published over the last ten years is provided as Attachment B.

The following statement addresses key features of the partial settlement of issues related to reliability must-run (RMR) contracts, and is submitted in accordance with Section IIC of the February 4, 1999 Memorandum of Agreement to Finalize Settlement signed by parties in the settlement negotiations. Section I briefly summarizes market distortions created by current RMR contracts. The second section summarizes key features of the modified RMR contract filed in conjunction with this partial settlement which are likely to impact the design and efficiency of California's energy markets. Section III summarizes the likely impacts of the new contract and other features of the partial settlement on the design and efficiency of California's energy markets.

I. Market Distortions Created by Current RMR Contracts

A. RMR Contract Payments

Three forms of RMR contracts currently exist, which are commonly referred to as Contract A, B and C.

Under Contract A, when units are called upon to operate at a specific level in order to maintain system reliability requirements, they receive a variable cost payment based on the unit's variable operating costs, any applicable start-up costs, plus a

"Reliability Payment" that covers a portion of the unit's fixed costs. This Reliability Payment is intended to enable units to recover fixed costs over the course of a year, but is paid on a per MWh basis only when units provide energy in response to an RMR dispatch notice.

Under Contract B, the ISO pays 100% of the fixed costs of the unit to the owner "up-front," *i.e.*, in monthly "Availability Payments" not associated with specific calls on the unit for reliability services. Units under Contract B are then reimbursed only for variable operating costs and startup costs (if applicable) whenever the unit is scheduled through the day ahead energy market, and is called upon to provide energy to maintain reliability pursuant to an ISO dispatch notice. When units on Contract B are not called upon for reliability services, or when they have capacity available in excess of the ISO's reliability requirements, they may participate in the market, but their owners must credit 90% of the profits earned in the market against the fixed-cost payments received from the ISO.

Under Contract C, owners receive full fixed costs, but earn no market revenues from RMR units. Contract C units are only dispatched when needed to meet RMR requirements, with owners being reimbursed for variable operating costs each time a unit is dispatched. In 1998, no units were under Contract C, but as of March 1999, 596 MW of RMR capacity are under Contract C.

The current structure of both Contract A and Contract B creates incentives for unit owners to withhold capacity or bid very high in the PX Day-Ahead Market. First, the owner of a unit under Contract A that is entitled to a relatively high Reliability Payment faces an opportunity cost of winning in the PX Day-Ahead Market (which is run before the ISO calls upon RMR energy), namely, the loss of the Reliability Payment. The owner of a unit under Contract A therefore has an economic incentive to not bid into the PX Day-Ahead Market, or to bid at a higher level, whenever there is a high probability that the ISO will call upon the unit to provide RMR service, and revenues from the Reliability Payment would exceed net revenues from scheduling the unit's energy in the PX Day-Ahead Market.

The second problem, which applies to units under both Contract A and B, is that an owner with RMR units and non-RMR capacity has an incentive to not bid RMR capacity into the PX Day-Ahead Market or to bid RMR capacity at higher prices in order to benefit the other capacity in its portfolio. Since, under Contract B, the owner must rebate 90% of any profits from the market to the ISO, it faces a relatively small opportunity cost from not participating in the market. By foregoing the small share of profit (10%) that it might retain if it did participate, *i.e.*, by withholding the anticipated RMR energy from the PX Day-Ahead Market, the owner may be able to raise the Market Clearing Price, to the benefit of its other capacity.

The contract features described above provide a rational, profit-maximizing RMR owner with an incentive to withhold capacity or to bid higher prices in the PX Day-Ahead

Market. Although such bidding practices are perfectly rational profit-maximizing behavior for owners of generation resources, the resulting market distortions are inconsistent with the functioning of an efficient competitive market, and, ultimately increase costs for California consumers. Such bidding practices or withholding not only increases the direct costs to the ISO, through increased RMR payments, but also causes significant indirect costs to consumers, by improperly raising market prices.

Both the MSC and the MSU have sought to estimate the level of distortion that may have occurred during the 1998 peak period. Both reports estimated the potential costs to California consumers of the market distortion to be in the hundreds of millions of dollars. However, for purposes of considering the benefits of modifications to RMR contracts under this partial settlement, it is not necessary to fix the amount of the cost increase to any level of precision. Whatever the amount, whether it be $100 million or $500 million, it is in the best interest of California, its consumers and their suppliers, that the focus now be on the modifying RMR contracts to ensure a workably competitive market in the peak period of 1999.

During the 1998 summer peak, the market was in its very formative stage. Owners of generation resources were just beginning to test the market. The lessons learned will not be lost on 1999 participants. They can be expected, understandably, to exploit fully the profit potential inherent in the “A” and “B” contract structures. Whether or not these bidding strategies were used in 1998, it cannot be assumed that they will be ignored during the 1999 peak period, to the profound detriment of California markets and consumers. Absent change before the summer of 1999, the resulting increase in cost to California consumers could certainly be in the hundreds of millions of dollars.

<u>B. Dispatch of RMR Units After Day-Ahead Market</u>

The second way in which RMR contracts distort California’s energy market results from the current practice of dispatching RMR units after the PX Day-Ahead Market. This market design ignores the fact that this generation must run and ultimately will be used to meet demand, and results in excess supply being purchased in the Day-Ahead Market. Purchasing this excess supply, in turn, increases the PX price. In other words, the MCP would be lower if demand in the Day-Ahead Market was not artificially inflated by the inclusion of demand that must ultimately be met by RMR generation. This requires that consumers pay twice for the local reliability provided by RMR units: once through direct fixed cost payments to generators, and again through higher PX prices. Under current ISO protocols, this excess supply “spills over” into the real time imbalance market. When demand in real time is less than the amount of RMR generation dispatched by the ISO after the close of the Day-Ahead Market, suppliers must be decremented to balance supply and demand in real time. If demand in the ISO’s real time imbalance market (or actual demand minus scheduled demand) exceeds RMR generation called by the ISO for local reliability purposes, this excess supply created by RMR generation is, in effect, treated as “must take” in the real time market. This practice may increase real time demand by encouraging buyers to underschedule demand in hopes of receiving lower real time prices, and thereby increasing price volatility.

Attachment A provides a more detailed explanation of the market distortions created by the current practice of dispatching RMR units after the PX Day-Ahead Market.

The MSU's *Report on Impacts of RMR Contracts on Market Performance,* included as Attachment C, provides a more detailed analysis of the economic incentives created by current RMR contracts, and the potential impacts of withholding or strategic bidding of RMR capacity on market costs.

II. Summary of Key Features of Partial Settlement

This section summarizes key features of the partial settlement related to the design and performance of California's energy markets.

A. RMR Contract Condition 1

Contracts A and B are replaced with a "market participation" contract, referred to as Condition 1 under the new contract. Under Condition 1 of the new contract:

1. Generation owners retain 100% of market revenues.

2. Compensation for RMR services is provided primarily in the form of a fixed cost payment, paid in monthly installments with adjustments made based on actual unit availability. The payment will include pre-payment for startup costs, based on total number of startups for market and non-market transactions.[1] However, the fixed cost payment for each unit under Condition 1 has not yet been determined, but instead has been reserved for litigation. On an interim basis, fixed cost payments will be based on levels filed with the partial settlement, with differences between these interim and final fixed cost payment levels resolved through a refund or surcharge payment made once final payment levels are determined.

3. RMR dispatch notices will be provided after the close of the Day Ahead energy and Ancillary Service markets. The agreement provides that anytime after October 1, 1999, the ISO may file with FERC for authorization to allow the ISO to issue

[1] Any of the proceeding 5 years may be used to determine the number of start-ups upon which the annual fixed payment for startup cost would be determined, with the specific year being selected by the ISO. (4.11(a) (iii)).

dispatch notices for RMR energy prior to the opening of the Day-Ahead Market, with a requirement that RMR owners electing the contract payment be treated as must-take in the PX Day-Ahead Market.

4. Upon receiving a dispatch notice, RMR unit owners would have the option of selecting between a market and contract transaction (5.5).

   a. Under the contract path, owners would be reimbursed for variable operating costs of energy provided to meet RMR requirements.

   b. Under the market transaction path, owners would notify the ISO of the market in which it intends to schedule generation necessary to meet RMR requirements (Day Ahead, Hour Ahead, or real time imbalance). If the owner intends to substitute a market transaction in the Hour Ahead or real time market, RMR energy is to be treated as must-take in the selected market, through a requirement that the owner submit an energy bid at a price of zero for an amount of energy equal to or greater than the owners RMR requirement(s) being met.

5. Owners will receive payment for any ancillary service capacity which RMR units win in the Day-Ahead Market, but are pre-empted from providing are due to RMR energy requirements established after the close of the Day-Ahead Market.

B. <u>RMR Contract Condition 2</u>

Under the partial settlement, the current Contract C is, in effect, replaced by Condition 2 of the new contract. Under Condition 2 of the new contract:

1. Generation owners do not retain any market revenues from operation of units; revenues from market transactions are credited to transmission owners.

2. Compensation for RMR services is provided primarily in the form of a fixed cost payment, with adjustments made for actual unit availability. Fixed cost payment for each unit under Condition 2 has not yet been determined, and may be reserved for litigation.

3. When units under Condition 2 are dispatched for RMR, energy necessary to meet RMR requirements will be bid into the subsequent energy markets as must-take.

4. Units under Condition 2 only participate in market transactions during hours when the ISO has issued a dispatch notice for the unit.

5. During hours when the ISO issues a dispatch notice for units under Condition 2, unit owners will be required to bid the full amount of energy and Ancillary Service capacity from these units into subsequent markets at rates specified in RMR contracts. For energy, bid levels are based on variable cost payments made to

generation owners. For Ancillary Services, bid levels are based on formula rates similar to those previously used to set cost-based price caps. Units under Condition 2 shall not otherwise engage in market transactions. 6.1(b).

III. Analysis of Market Impacts of Partial Settlement Features

This section summarizes the impact of the new contract and other features of the partial settlement in terms of improving the design and efficiency of California's energy markets.

A. RMR Contract Condition 1

1. **Elimination of Reliability Payment Under Contract A.** The elimination of the Reliability Payment under current Contract A removes the disincentive to schedule RMR units in the Day-Ahead Market when a) there is reasonable probability that units under Contract A will be called under RMR and b) market prices are lower than the total variable payment received if a unit is called under RMR (variable operating costs plus the Reliability Payment).

2. **Fixed Payment for Startup Costs**. Payment of startup costs through a fixed, pre-agreed amount, which is added to the fixed option payment received by each unit, removes another potential disincentive for unit owners to startup units and participate in the market when there is reasonable probability of being called under RMR.

3. **Retention of All Market Revenues by Unit Owners**. As previously noted, the requirement that units under the current Contract B refund 90% of market revenues has the effect of reducing the opportunity cost of withholding RMR capacity from the market or bidding capacity from RMR units at higher prices in order to increase market prices earned by other units in a generator's portfolio. By allowing units to retain 100% of market revenues, Condition 1 of the new contract removes this disincentive. On a practical level, this modification also avoids implementation problems associated with the current requirement that 90% of market revenues for units under Contract B be credited back to transmission owners. This modification also avoids potential gaming opportunities associated with affiliate transactions, and how generation owners may choose between scheduling RMR and non-RMR generating units in their portfolio to meet their Day Ahead supply schedule.

4. **Compensation through Fixed Option Payment.** By providing compensation to RMR units owners primarily through a fixed pre-agreed option payment, the new contract provides a more transparent and easily quantified price signal reflecting the premium being paid to meet local reliability requirements through RMR contracts. This price signal can be used by the ISO and other market participants to develop and assess competitive alternatives for meeting the local reliability requirements through new generation facilities, transmission system upgrades, or other options

(e.g. demand reduction). In this manner, the structure of the new RMR contracts will more effectively promote longer-term competition among different alternatives for meeting local reliability requirements.

B. RMR Contract Condition 2

1. **Market Participation Under Condition 2 of the New Contract**. Under the new contract, units selecting to operate under Condition 2 of the contract would retain no market revenues, but would receive full fixed costs plus variable operating costs. Thus, Condition 2 in effect replaces Contract C of current RMR agreements. Bidding rules of Condition 2 of the new contract require the full capacity of units to be bid into energy and ancillary service markets during hours when they are dispatched for RMR, and would therefore result in a significantly higher level of market participation than exists under the current Contract C. However, overall market participation of units under Condition 2 would be significantly decreased relative to historical levels, as well as levels of market participation under Condition 1. For instance, analysis of 1998 operating data for RMR units indicates that under bidding rules for units under Condition 2, the amount of energy and Ancillary Services provided by RMR units switching to Condition 2 could decrease by as much as 35% and 63%, respectively, compared to the amount of energy and Ancillary Service capacity provided by these units during 1998.[2] Decreased market participation by units under Condition 2 would result in higher energy and Ancillary Service prices.

2. **Fixed Cost Payment**. First, it is important to note that the level of fixed cost payments for units under Condition 2 of the final settlement primarily involve issues of equity, rather than economic efficiency. An important exception to this is that option payments must be such that units do not have an incentive to select Condition 2 rather than Condition 1. This issue is discussed below in item 2d. A few comments regarding the equity of option payments are provided below in item 2c.

C. Key Unresolved Issues

Under the partial settlement agreement, two key unresolved issues with significant potential impacts on the design and efficiency of California's energy markets are reserved for further negotiation and potential litigation.

1. **Level of Fixed Option Payment**. The level of fixed option payments for units under Condition 1 in the partial settlement are interim, and are subject to adjustment through a refund or surcharge, depending on the outcome of further negotiation and potential litigation. The objective of the annual fixed option payment is to 1) fairly

[2] Calculated for the period from April to December 1998, based on the sum of scheduled energy and Ancillary Services provided by an RMR unit during hours when that unit had a Minimum Reliability Requirement specified by the ISO for that hour, as a percentage of the total amount of scheduled energy and Ancillary Services provided by RMR units over this same time period.

compensate unit owners for any incremental costs associated with keeping RMR units available to meet reliability requirements when dispatched by the ISO (including a fair market return on these costs), and 2) ensure that any RMR units which could not cover fixed going forward costs through net market operating revenues are not mothballed, and are maintained and available for use in maintaining system reliability.

a) Assessing whether fixed cost payments meet this first objective — fair compensation for any *incremental* costs associated with keeping RMR units available to meet reliability requirements — would require an assessment of the actual *incremental* costs associated with keeping RMR units available to meet reliability requirements. However, it is important to note that incremental costs to generators associated with RMR contracts are likely to be significantly different – and *lower* – than option payments that would result from the type of fixed cost allocation initially proposed by generators, under which a unit's total fixed costs were allocated between RMR and non-RMR service based on either the percentage of hours during which a unit was called under RMR or the total amount of energy dispatched under RMR as a percentage of a unit's total annual production. Both these approaches are likely to over-allocate costs to RMR service, given that they are based on allocation of a unit's total fixed costs, rather than the *incremental* costs associated with providing services under RMR contracts.

b) Providing fair compensation for any *incremental* costs associated with meeting reliability requirements under RMR contracts also requires that unit owners receive compensation for the *opportunity cost* of any energy or Ancillary Services which units may be unable to provide through the market as a result of being dispatched by the ISO for reliability energy. The interim RMR settlement accomplishes this in two ways: by allowing unit owners to select the "market path" for energy after receiving a dispatch notice from the ISO, and by directly compensating owners for any Ancillary Service capacity they bid and are awarded in the Day-Ahead Market, but are unable to provide due to an RMR call. If protocols are ultimately modified so that RMR is dispatched *prior* to the Day-Ahead Market, an alternative way of compensating RMR owners for these opportunity costs must be developed. The basic options for such compensation include a fixed up front payment for opportunity costs of lost market revenues due to RMR dispatch requirements, or a variable payment tied to actual market prices and capacity "pre-empted" from participating in the market due to RMR dispatches. If the second option is ultimately pursued, care must be taken to structure any such variable "opportunity cost" payment so that it does not create gaming opportunities or other incentives which affect the actual market decisions of generation owners.

c) The second major objective of the fixed cost payment — ensuring that any RMR units which could not cover fixed going forward costs through net market operating revenues are not mothballed — can be met by basing fixed cost payments under Condition 1 of the contract based on a "net-of-market" approach. Under this approach, a floor for fixed cost payments would be set based on each unit's fixed cost, *minus* a reasonable estimate of potential market revenues from sales of energy and Ancillary Services. For purposes of ensuring that units needed for reliability are not "mothballed", fixed costs used in this calculation need only include going forward fixed costs, rather than total fixed cost (including capital recovery payments covering *sunk* costs).

d) The need to offer the type of contract represented by Condition 2 stems from the potential that some generating units which are needed for system reliability would be unable to cover variable and fixed operating costs without additional payment received through RMR contracts, and could therefore be shut down and unavailable for use in maintaining system reliability. As described above, the basic rationale for needing to offer Condition 2 can be eliminated if the fixed option payment under Condition 1 includes a component based on the type "net-of-market" calculation described above. In addition, it should be noted that if Condition 2 is offered for purposes of ensuring that units needed for reliability are not "mothballed", fixed costs offered under Condition 2 only need to include going forward fixed costs, rather than total fixed cost (including capital recovery payments covering *sunk* costs). Costs that are already sunk should have no bearing on a generator's decision to keep a unit in operation. Indeed, the extent to which a generator receives compensation for going forward costs and retains the ability to earn a contribution to recovery of its sunk costs through future market transactions, it would be economically rational to maintain the unit in operation.

e) If RMR unit owners are allowed to select between Condition 1 and Condition 2 of the new contract, each owner will select whichever contract option provides the greatest perceived benefit in terms of return on investment, taking into account the risk associated with the uncertainty surrounding market outcomes. For instance, financial payments associated with Condition 2 are highly predictable, while returns under Condition 1 depend on uncertain market outcomes. If the level (or formula) of fixed option payments to units under Condition 1 are such that a significant amount of RMR capacity would opt to select Condition 2 of the contract, overall market participation by RMR units would be significantly reduced, with the result being higher prices in both energy and Ancillary Services markets. As noted above, analysis of 1998 operating data indicates that with proposed bidding rules for units under Condition 2, the amount of energy and Ancillary Services provided by RMR units switching to Condition 2 is likely to decrease significantly relative to the amount of energy and Ancillary Service capacity provided by these units during 1998. Thus, fixed option payments under Condition 1 and Condition 2 must be carefully structured in order to avoid having a significant amount of capacity under Condition 2 of the new contract. Applying a "net-of-market" approach to the calculation of the appropriate payment to units operating under either Condition would accomplish this objective.

f) **Treatment of RMR as Must-Take in Day-Ahead Market**. The interim settlement eliminates the major features of Contract A and B that reduce the economic incentive for RMR units to participate in the energy and Ancillary Service markets. However, the variable cost payment received when units are called to provide RMR energy can still provide an incentive for units not to participate in the Day-Ahead Market during hours when market prices are lower than variable operating costs, but it is nonetheless economic for units to continue operating at minimum levels due to start-up costs and other operating constraints. Thus, the only way to eliminate the effect of these variable cost payments entirely is to pre-dispatch RMR generation and treat this energy as must-take in the Day-Ahead Market.

As outlined in more detail in Attachment A, treating RMR generation as must-take in the Day-Ahead Market (by either a zero bid in the PX or scheduling RMR in the day ahead schedule through bilateral contracts) represents the most economically efficient and equitable design for California's energy markets. The agreement to defer the issue of treating RMR as must-take in the Day-Ahead Market represents a major concession made by the ISO in the interest of reaching a partial settlement agreement under which modified RMR contracts could be implemented by the summer of 1999. However, by allowing the ISO the right to file for FERC approval of a tariff provision for treatment of RMR as must-take in the Day-Ahead Market on or after October 1, 1999, the partial settlement allows for this key issue to undergo thorough consideration by FERC, without delaying implementation of the other modifications to current RMR contracts described above prior to the critical peak load season of 1999.

IV. Conclusion

Although the partial settlement does not achieve an optimal solution from the perspective of overall market efficiency, it would significantly improve market efficiency relative to the current contract structure. By allowing the ISO the right to file for FERC approval of a tariff provision for treatment of RMR as must-take in the Day-Ahead Market after October 1, 1999, the partial settlement allows for this key issue to undergo thorough consideration by FERC and ultimately be implemented, without delaying implementation of the other modifications to current RMR contracts described above prior to the critical peak load season of 1999. For this reason it is critical that the partial settlement and associated tariff modifications be approved in time for them to be effective by June 1, 1999.