CALIFORNIA ISO

Pre-dispatch and Scheduling of RMR Energy in the Day Ahead Market

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California Independent System Operator
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Executive Summary

This report analyses the operational and market impacts of the manner in which Reliability Must Run ("RMR") generating units are dispatched and scheduled pursuant to the California ISO Tariff and the contracts between the ISO and the RMR unit owners.

The design of the restructured California electricity market rests on a number of fundamental principles. One of these principles is that all schedules submitted to the ISO by all Scheduling Coordinators must be balanced, with loads equaling supply. A second key feature is that California's market is designed so that anticipated demand should be scheduled in the Day-Ahead Market, in order to facilitate efficient and reliable generation scheduling decisions.

RMR generating units are currently dispatched and scheduled in a manner that departs from these principles. Generation that is necessary from RMR units to maintain local system reliability is not scheduled in Day Ahead energy market and does not appear in any Scheduling Coordinator's Balanced Schedule. After final Day-Ahead schedules are submitted to the ISO, additional generation required from RMR units to maintain local reliability that has not been scheduled in the Day Ahead market is dispatched by the ISO. This energy then appears in real-time, unscheduled against any demand. Because this additional generation from RMR units must ultimately be used to meet demand, the ISO must often take action in real time to address this unscheduled generation by decrementing other generation scheduled in the Day Ahead market.[1]

Current protocols for dispatching RMR generation negatively impact ISO operations, reliability and overall energy markets both *directly* and *indirectly.*

Direct Impacts

The *direct* impacts of allowing RMR energy to appear in real time unscheduled against demand include the following:

- **Increased uncertainty and volatility of real time demand and prices**. The excess supply created by RMR generation must often be offset by decrementing other scheduled generation in real time. At the same time, the anticipation of unscheduled RMR energy "spilling over" into real time may create an incentive for buyers to attempt to take advantage of this "must take" generation by shifting a portion of demand to the real time markets. Due to the inability of buyers to forecast perfectly this "supply" of RMR energy and co-ordinate any shift in demand to the real time

[1] Additional discussion of how current RMR dispatch protocols are inconsistent with the overall design of California's energy markets and the ISO's responsibility for grid management is provided in a memorandum from Professor Robert Wilson, Stanford University, Graduate School of Business, provided as special consultant to the ISO's Department of Market Analysis (included as Attachment A to this report).

market, any such shift in demand is likely to be imperfect and thereby add unnecessary volatility to real time market demand and prices.[2]

- **Decreased efficiency of supply commitment and scheduling decisions.** In addition to increasing the volatility of real time demand, allowing RMR energy to appear unscheduled in the real time market decreases overall supply efficiency by increasing the need to *increment* and *decrement* in real time other units with generation schedules. Analysis presented in this report indicates that about 25% of RMR energy dispatched after the Day Ahead market, which appears in real time unscheduled against demand, has required that the ISO decrement other generation that was scheduled against demand in the Day Ahead market. This decreases overall supply efficiency by reducing the ability of generation operators to optimally commit and schedule portfolios of supply resources based on expected load conditions and price signals in the Day Ahead and Hour Ahead markets. Due to the "thinness" of supply of decremental energy bids during many hours, the ISO has on numerous occasions needed to resolve over-generation by accepting negative decremental energy bids (which represent suppliers being paid *not* to generate), and by making special *out-of-market* and *out-of-control area* arrangements to decrement generation or export excess energy.

- **Increased Ancillary Service costs.** The ISO must defend against real time load and generation uncertainty and volatility by procuring Ancillary Services. By increasing the volatility of real time system imbalances, unscheduled RMR energy (along with other factors affecting real time demand) increases the amount of regulation the ISO must purchase to manage load fluctuations, and thereby imposes unnecessary costs on demand met through the ISO system.

- **Reliability Risks**. Increased purchases of ancillary services can reduce, but not eliminate the potential impacts of system load imbalances under various contingencies on system reliability. Thus, allowing RMR energy to "spill over" into real time unscheduled against demand ultimately creates increased risks relating to system reliability by increasing the uncertainty and volatility of real time load imbalances.

Indirect Impacts

Allowing RMR energy to appear in real time unscheduled against demand also impacts the Day Ahead energy markets *indirectly*, resulting in significant market distortions and inefficiencies, as described below:

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[2] As an interim measure to reduce the effect RMR dispatches on the Day Ahead market, the Commission recently directed the ISO to provide information to Market Participants on the amount of RMR energy requirements that the ISO's estimates will not be scheduled in the Day Ahead market (*87 FERC ¶ 61,208 1999* (May 26, 1999). However, since different buyers cannot co-ordinate the quantity each of these Market Participants purchase in the Day Ahead market, the amount of total aggregate demand that may be shifted out of the Day Ahead market in response to this information can only be imperfect at best.

- **Purchase of excess supply in Day Ahead market**. The ISO requires that final Day Ahead (and Hour Ahead) schedules submitted by all Scheduling Coordinators (SCs) be balanced, with supply schedules equaling demand. Current RMR protocols are inconsistent with this key element of California's market design. Although final schedules submitted by SCs include demand that can only be met by generation from RMR units, these schedules do not necessarily include the RMR energy that must ultimately be called upon to meet that particular demand. This results in excess supply being purchased in the Day Ahead market and scheduled against demand that must ultimately be met by RMR generation. The purchase of this excess supply increases the PX Market Clearing Price ("MCP") and distorts market price signals, because the MCP does not reflect the actual cost (or bid price) of supply needed to meet demand in the PX Day Ahead market. This also 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. Analysis presented in this report indicates that current RMR dispatch protocols significantly distort prices in the PX market and increase total market costs by up to about $110 million per year, or about 2% of total energy costs in the PX and real time markets.

- **Withholding of capacity from Day Ahead market in order to receive Variable Cost Payment.** Since RMR requirements are based primarily on forecasted load and unit operating characteristics, RMR owners can predict whether they will be dispatched under RMR contracts with a high level of certainty. The new RMR contracts that took effect in June 1999 eliminated the major incentives to withhold capacity (or bid uncompetitively high prices) in the Day Ahead market that existed under previous RMR contracts.[3] However, the Variable Cost Payment ("VCP") received by units called after the Day Ahead market still provides an incentive for RMR unit owners to refrain from scheduling RMR capacity in the Day Ahead market when units must continue to operate at minimum levels due to operational constraints and the PX MCP is lower than the unit's VCP. The VCP also serves as a "backstop" payment for any RMR requirements not scheduled in the Day Ahead market, and thereby reduces the potential opportunity cost for generators who bid their resource portfolios into the PX above their variable costs in order to increase market clearing prices. Under such a bidding strategy, if the RMR owners are not awarded enough capacity in the Day Ahead market to schedule RMR units which are on-line and must continue generating at some level, the VCP allows them to recover full operating costs for any RMR generation called by the ISO for reliability purposes. This "backstop" payment reduces the trade-off between higher market prices and lower market sales that such bidding strategies typically create for generators, and thereby facilitates the strategic bidding aimed at increasing the MCP. Analysis presented in this report indicates that about 16% of RMR requirements not scheduled in the Day Ahead market over the summer 1999 period represent energy that

[3] These include the Reliability Payment under Contract A and the credit back provisions of Contract B. See "Report on Impacts of RMR Contracts on Market Performance," prepared by the Market Surveillance Unit (currently Department of Market Analysis), California Independent System Operator (March, 1999), included as Attachment E to the transmittal letter of the ISO's filing for the tariff changes which are the subject of this report

needed to be generated by units operating at minimum levels during hours when the PX MCP was less than the units' VCP. Another 13% of RMR requirements were not scheduled in the Day Ahead market even though these thermal units were in operation, and the hourly PX MCP exceeded the unit's VCP. Thus, a total of about 29% of RMR energy dispatched after the Day Ahead market represents energy that would have been economic to schedule in the Day Ahead market in the absence of the VCP.

Proposals to Address These Impacts

The Department of Market Analysis ("DMA") believes that the negative direct and indirect impacts of current RMR dispatch procedures are each sufficient to warrant modifying tariff and dispatch protocols. To address these impacts, the ISO is proposing tariff amendments that would revise RMR dispatch procedures as follows:

(1) Allow the ISO to dispatch RMR units for local reliability purposes by notifying them of their Minimum Reliability Requirement *prior* to the Day Ahead market. The modification is referred to as *pre-dispatch* since it allows the ISO to notify RMR units of their minimum operating requirements prior to, rather than after, the PX Day Ahead market. Upon receiving a dispatch notice from the ISO, owners will continue to have the option of electing to provide this energy through a market transaction or under the RMR contract path, according to which owners receive payment for full variable costs.

(2) Require that energy provided under the RMR *contract path* be scheduled against demand in the Day Ahead market. Under California's market design, this requirement can be most efficiently implemented by requiring that RMR energy being provided under the contract path be bid as must-take in the Day Ahead PX market, i.e., at a bid price of zero. This modification is referred to as *netting out,* since it essentially *nets out* the amount of load that must ultimately be met by energy provided under RMR contracts from total demand in the Day Ahead market. By effectively netting out demand that must be met by RMR generation under the contract path from demand in the Day Ahead market, this avoids purchase of excess supply and distortion of the MCP in the PX market.

(3) Require that RMR energy provided through the *market substitution path* be scheduled against demand in either the Day Ahead or Hour Ahead schedules submitted to the ISO. This modification is designed to ensure that RMR requirements being met through market transactions are scheduled against demand in the Day Ahead or Hour Ahead markets, rather than appearing unscheduled against demand in real time. If RMR energy being provided under this path is not scheduled against demand prior to the Hour Ahead market, it must be bid as "must-take" (i.e., at a price of zero) to ensure that it is scheduled against demand and does not "spill over" into the real time imbalance market. Actual sales of this energy may be made through any of the PX markets or bilateral transactions.

These proposed modifications in RMR dispatch and scheduling protocols are intended to mitigate or eliminate the direct and indirect effects noted above. They would align the treatment of RMR generation with the fundamental principles underlying the California electricity market design, while preserving the flexibility of RMR owners to participate in market transactions. These modifications were key elements of RMR contract reforms developed by the ISO in the context of 1998 RMR contract negotiations, in consultation with the ISO's Department of Market Analysis and its Market Surveillance Committee, and with the support of a coalition of stakeholders including transmission owners, the California Public Utilities Commission (CPUC), California Energy Commission (CEC), and Energy Oversight Board (EOB). Under the partial RMR settlement agreement reached in the spring of 1999, the ISO agreed to defer resolution and implementation of these key market reforms in order to ensure that other critical RMR contract reforms could be implemented prior to the 1999 summer peak load period.

The ISO is continuing to implement a variety of measures to decrease or eliminate features of the California market design that have created highly volatile, often excessive demand for both incremental and decremental energy in the ISO's real time market. The DMA believes that the proposed modifications to RMR dispatch protocols represent one of the most important components of this overall market redesign effort. In combination, the ISO expects implementation of these measures to have significant direct benefits in terms of reduced market and system volatility, increased efficiency and reliability, and reduced Ancillary Service requirements costs. As noted above, the DMA believes that the direct benefits alone would justify the proposed tariff changes.

In addition to these direct impacts, the DMA believes current RMR dispatch procedures impose even more significant costs on market efficiency and consumers due to the indirect effects of excess supply purchased in the PX market to meet demand that must ultimately be met by RMR generation. Precise quantification of these indirect impacts based on historical market data is difficult due to the ability of buyer and sellers to arbitrage between the Day Ahead markets, and the variety of different factors that have to date created distortions which hinder the ability for California's different energy and markets to equilibrate. The impact of RMR dispatch protocols on the Day Ahead market may be offset in part by buyers "shifting" demand from the PX to the real time market. However, actual day-to-day price trends, which show significant and systematic price differences in these market for many periods of time, indicate that the ability of buyers to arbitrage between these two markets is very imperfect. Therefore, the DMA believes – based on both economic theory and actual market performance – that these indirect impacts are likely to be significant. Analysis presented in this report indicates the magnitude of these indirect impacts is significant, representing millions of dollars of market costs.

Finally, it should be noted that the netting out of RMR generation prior to the Day Ahead market also brings the treatment of such generation into line with the basic design of the restructured California electricity markets. To implement the ISO's function of managing the grid independently of the energy markets, the ISO accepts only balanced schedules from Scheduling Coordinators. To be consistent with this principle, the energy acquired from RMR units to ensure local reliability, which can be determined and dispatched by the ISO just prior to the PX Day Ahead market, should be balanced against load in the Day Ahead or Hour Ahead market. If this is not done, then the aggregate of the Scheduling Coordinators' balanced schedules and the unsold RMR energy is unbalanced, forcing the ISO to address this situation in the real-time energy market, which was not designed for this purpose.

The reminder of this report is organized as follows. Section 1 provides a background on current RMR tariff and contract protocols, and outlines the ISO's proposed protocols for issuing RMR dispatch notices prior to the Day Ahead market and scheduling of RMR generation being provided under RMR contracts in the Day Ahead market. Section 2 outlines the economic and operational rationale for the proposed modifications in RMR dispatch. Section 3 presents results of quantitative analysis of the impacts of proposed modifications in RMR dispatch based on recent market data.

1. Background

1.1 Reliability Must Run (RMR) Requirements

Reliability Must Run (RMR) agreements are an integral part of California's market design, and provide a variety of functions:

- **Local Reliability**. RMR units are designated based on their location on the transmission grid and their ability to ensure local reliability by providing voltage support, black start capabilities, adequate local generation in the event of system contingencies and other local reliability services. The most frequent use of RMR units to ensure local reliability occurs when the ISO establishes an hourly Minimum Reliability Requirement for each RMR unit prior to each operating day. The minimum Reliability Requirement is based on expected system load and transmission conditions, as well as minimum start-up times, operating levels and run times specified in the unit's RMR contract. This report focuses on the impact of proposed changes in how the ISO ensures these Minimum Reliability Requirements are met, and how energy that must be generated to meet these requirements is incorporated into California's markets and system operations.

- **Mitigation of Local Market Power**. Units providing local reliability services have locational market power due to their unique ability to provide these services for a specific portion of the transmission system. RMR agreements are a means of mitigating this local market power by establishing terms under which the ISO can call upon these units to provide local reliability services outside of the market.

- **Real Time Intra-zonal Congestion Management and System Reliability**. A less frequent, but critical, use of RMR units is to manage intra-zonal congestion and system imbalances in real time. For instance, the operating schedule of RMR units may be adjusted in real time in order to resolve intrazonal congestion when the adjustment bid market is not workably competitive due to the limited number of generators who could be called to relieve the congestion.

- **Ancillary Services**. The ISO has the ability to call RMR units to provide Ancillary Services in the event there is insufficient supply offered through competitive markets. Although the ISO frequently called upon RMR units to provide Ancillary Services during its first summer of operation, the ISO has not needed to call upon RMR units to provide Ancillary Services since new RMR contract payment reforms took effect in June 1999.

As noted above, this report focuses on the first use of RMR described above, which accounts for the bulk of RMR generation dispatched by the ISO.

1.2 Current RMR Dispatch Protocols

After final Day Ahead schedules are submitted to the ISO by all Scheduling Coordinators (SCs), the ISO determines the minimum necessary operating level, or the Minimum Reliability Requirement, for each RMR unit for each hour of the following operating day. The hourly Minimum Reliability Requirement for each RMR unit is based on expected system load and transmission conditions, as well as operating constraints of individual RMR units specified in RMR contracts. For instance, if a thermal unit (other than a combustion turbine peaking unit) is needed for local reliability during peak hours of the day, the RMR contract would typically require that unit's Minimum Reliability Requirement be set no lower than the unit's minimum operating level during off-peak hours, due to the unit's start-up time, minimum operating level and minimum operating time.

After determining the hourly Minimum Reliability Requirement for each unit, the ISO then compares this requirement to the final Day Ahead schedule submitted by each RMR unit. If the Minimum Reliability Requirement is greater than the unit's final Day Ahead schedule, the ISO issues a Schedule Change to the RMR unit operator, indicating any increase in the unit's Day Ahead Schedule necessary to ensure the unit operates at or above the Minimum Reliability Requirement for each hour. The table below illustrates this calculation for a hypothetical RMR unit:

	Final DA Schedule	Minimum Reliability Requirement	Schedule Change
Hour 1	0	30	30
Hour 2	20	30	10
Hour 3	50	30	0

Dispatch notices are issued to RMR unit owners, notifying them of both the Minimum Reliability Requirement and any necessary Schedule Changes. Owners are required to operate units at or above the Minimum Reliability Requirement. If a Schedule change is necessary, the new RMR contracts in effect since June 1999 provide owners with the option of meeting Reliability Requirements through either a *market* or *contract* path.

Market Path. Under the market path, owners can either schedule RMR energy in Hour Ahead market or run at the required level in real time unscheduled against demand. Under the first option, the RMR owner receives all revenues from sales of RMR energy in either the PX's Hour Ahead market or through a bilateral transaction incorporated in the unit's final Hour Ahead schedule submitted to the ISO. Under the second option, generation provided to meet the Minimum Reliability Requirement (the Schedule Change) is, in effect, treated as any other uninstructed deviation from a unit's final Hour Ahead schedule: the owner is paid the real time imbalance price for additional generation above the unit's final HA schedule. The market path was included in the new RMR contracts at the request of RMR owners, who wanted an option to earn Hour Ahead or real time market prices for energy being provided under a Schedule Change. Owners can be expected to elect this path when projected market prices exceed the variable cost of operation. Over the first three months since the new RMR contract has been in effect, less than 1.4% of total RMR Schedule Changes issued after the Day Ahead market (excluding real time dispatches) have been provided under this market path.

Contract Path. Under the contract path, RMR owners must operate at the level necessary to meet their Minimum Reliability Requirement and receive a Variable Cost Payment ("VCP") covering their full costs of operation rather than the market price.[4] RMR energy included in a Schedule Change under this contract path appears unscheduled against demand in real time and has, in effect, the same impact on the imbalance market as an uninstructed deviation.

As described above, when the ISO issues a Schedule Change under current practice, the energy included in the Schedule Change is energy that has not previously been scheduled in the PX Day Ahead market. The demand that the RMR energy is required (because of local reliability concerns) to serve has already been matched with energy in the Day Ahead market. The RMR energy is thus unscheduled "excess" energy. Unless the SC is able to schedule this energy in a later PX market, this energy will appear, unmatched to demand, in real time. As described in Section 2 of this report, this excess, unscheduled energy in real time has significant negative impacts on the energy markets and the ISO's operations.

1.3 Proposed Modifications in Dispatch Protocols

Tariff change being proposed by the ISO would modify existing protocols in three main ways:

1. **Pre-Dispatch of RMR requirements**. Prior to the Day Ahead market, the ISO will determine the minimum necessary operating levels, or the Minimum Reliability Requirements, for each RMR unit for each hour of the following operating day. The ISO will then notify each RMR unit operator of this Reliability Requirement through a dispatch notice issued by 5 a.m. RMR owners then have the option of electing to meet these reliability requirements through either the *market* or *contract* paths. RMR owners must notify the ISO of this election by 6 a.m., one hour before final bids must be submitted in the PX Day Ahead market.

2. **Netting out of demand met by RMR energy provided under contract path.** Under the contract path, RMR owners will continue to receive a Variable Cost Payment covering their full costs of operation, but will now be required to schedule energy in

[4] In practice, due to the ISO's settlement system, RMR owners receive the real time imbalance price for energy provided under the contract path. Owners then receive (or make) an additional payment to Transmission Owners for the difference between the imbalance price and their Variable Cost Payment.

the PX Day Ahead market.[5] To ensure that the required amount of generation from RMR units can be scheduled against demand in the PX Day Ahead market, RMR owners will be required to submit a zero-priced bid in the PX Day ahead market for a quantity equal to (or exceeding) their RMR requirements being met under the contract path. This has the effect of making RMR generation "must-take" in the PX market, and ensures that the quantity of each RMR owner's portfolio bid into the PX that clears the market will be at least equal to the amount of RMR generation each owner must provide under the contract path.

3. **Requirement that energy under market substitution path be scheduled against demand, rather than appearing unscheduled in real time**. When being notified of RMR requirements by the ISO prior to the Day Ahead market, RMR owners will still be able to select the market substitution path. However, they will be required to schedule RMR energy in a forward market, through either the PX or a bilateral transaction. Owners can be expected to elect this path when projected market prices exceed the variable cost of operation. If the RMR owner bid in the Day Ahead market, but has not successfully scheduled the RMR generation, ensure that this energy is scheduled against demand prior to the real time market by submitting a zero priced bid into the next applicable PX market. Under the RMR contracts, if the unit initially bids into a market other than the Day Ahead market, it must also be bid at zero dollars.

RMR owners must notify the ISO of their election between the contract and market paths by 6 a.m., one hour after receiving the ISO dispatch notice and one hour prior to the close of bidding in the PX Day Ahead market at 7 a.m.

1.4 Impact of Other Market Design Flaws and Features

The unscheduled supply created by RMR generation is one of a variety of features of California's market design which have created incentives for buyers to shift demand in real time. Many of the Ancillary Service redesign features implemented in summer 1999 were aimed at correcting these problems by removing incentives for shifting both demand and supply into real time. These include the following:

- *Intentional mis-scheduling*. Although ISO protocols require that SC submit schedules that balance energy with *scheduled* loads, buyers are able to intentionally under- or over-schedule demand, with any difference being billed (or credited) at the real time imbalance price. The ability of buyers to "shift" demand to real time during peak

[5] Since the PX's financial settlement system is separate from the ISO's, RMR owners will receive payment for energy scheduled under the contract path from the PX. Therefore, these revenues must be credited against the Variable Cost Payment for purposes of financial settlements between the transmission owners and RMR owners. The crediting merely treats the energy sold in the PX by RMR units under the contract path as though it were provided by the participating Transmission Owner ("TO") that has, through the ISO, effectively contracted with RMR owners to provide this energy at a pre-agreed price equal to the Variable Cost Payment specified in the RMR contract.

periods represents a source of demand elasticity in the PX Day-Ahead market, which can help keep prices lower in the PX when high prices occur. For large buyers, shifting demand to real time can reduce overall purchase costs – even if real time prices exceed Day Ahead PX prices – since the PX price applies to the bulk of purchases, while the real time price only applies to any incremental demand met in the real time market. Currently, the ISO's market design does not "penalize" such shifting of demand, and until recently, settlement rules such as the billing of Ancillary Services based on scheduled rather than metered loads may have actually encouraged under-scheduling of demand.

- *Inaccurate Accounting for Transmission Losses in Schedules.* ISO protocols are designed to require that SCs submit schedules in which generation and loads are balanced *after* accounting for transmission losses. These losses are estimated for using Generation Meter Multipliers (GMMs) for each major supply and demand point on the transmission grid. However, schedules submitted to the ISO currently do not account for these losses due to a limitation in the PX scheduling software. Although the final settlement process accounts for these losses, the inability to apply GMMs to schedules creates a systematic scheduling imbalance, i.e., a deficit in the actual supply of energy available to meet scheduled load. This creates a systematic imbalance (or demand for incremental energy) in the real time market of as much as 2% to3% of total system loads. This systematic demand for real time energy will be eliminated when software changes necessary to apply GMMs to Day Ahead and Hour Ahead supply schedules are implemented.

- *Billing of Ancillary Services Based on Scheduled Demand***.** Until recently, Ancillary Service costs were billed based on scheduled load in the Day Ahead (and Hour Ahead) markets, rather than on actual metered loads. Over the last year, Ancillary Service costs have equaled at least 5 to 10% of Day Ahead energy costs. In effect, these Ancillary Service costs have represented an additional cost applied to energy purchased and scheduled in the PX, which has not been added to charges for real time imbalance energy. This has provided a direct incentive for buyers to "under-schedule" and to purchase a portion of their demand in the real time market, even if real time prices exceed the PX Day Ahead price. Software changes that were necessary to bill Ancillary Service costs based on metered loads became functional on August 17, 1999. Billing based on metered demand will correct this incentive to under-schedule loads. However, it is important to note that this key source of distortion between prices in the PX and real time market (and the incentive it has created to shift demand to the ISO's real time market) has existed over virtually the entire period of operation that must be used in any analysis of the impacts of RMR dispatch protocols.

As these and other incentives for under-scheduling of demand are removed or reduced, the unscheduled supply created by RMR generation will continue to create a significant source of uncertainty and volatility in real time demand unless RMR dispatch protocols are modified to ensure that RMR energy is scheduled against demand.

2. Impacts of RMR Dispatch Protocols

2.1 Direct Operational and Market Impacts

2.1.1 Increased Uncertainty and Volatility of Real Time Demand

The excess supply created by RMR generation must often be offset by decrementing other scheduled generation in real time. This occurs if supply and demand are otherwise in balance, or supply already exceeds demand in real time due to either "overgeneration" or lower than expected loads. At the same time, the anticipation of unscheduled RMR energy "spilling over" to real time may create an incentive for buyers to attempt to take advantage of this "must take" generation by shifting a portion of demand to the real time markets.[6] Due to the inability of buyers to forecast perfectly this "supply" of RMR energy and co-ordinate any shift in demand to the real time market, any such shift in demand is likely to be imperfect and thereby add unnecessary volatility to real time market demand.[7]

2.1.2 Decreased Efficiency of Supply Commitment and Scheduling Decisions

Allowing RMR energy to appear unscheduled in the real time market decreases overall supply by increasing the need to increment and decrement generation in real time, and reducing the efficiency of unit commitment and scheduling decisions made based on forward market conditions. Under California's market design, virtually all decisions regarding the commitment, scheduling and operation of specific generation units are made by unit operators, rather than the ISO. California's market is specifically designed to facilitate efficient unit scheduling decisions by allowing the bulk of unit commitment and scheduling decisions to be made immediately after the Day Ahead market, rather than in the Hour Ahead or real time markets. The real time imbalance market is designed primarily to ensure system reliability in the most efficient manner possible, based on incremental and decremental energy bids submitted by units which are able to increase or decrease unit operating levels in real time. Within this market design, increased reliance and volatility in the real time market time decreases overall supply efficiency by reducing the ability of generation unit owners to optimally commit and schedule portfolios of supply resources based on expected load conditions and price signals in the Day Ahead markets.

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6 In California's market design, buyers are free to "shift" a portion of expected demand into the real time market by simply submitting final schedules for a level of demand than is lower than actually expected. While final schedules submitted to the ISO must be balanced (with supply equaling demand), the amount of load scheduled may be significantly lower than is actually expected. The difference between actual loads and scheduled supply is then made up in the real time market, with the buyer paying the real time price for the amount by which actual loads exceed scheduled loads.

7 As an interim measure to reduce the effect RMR dispatches on the Day Ahead market, the Commission recently directed the ISO to provide information to Market Participants on the amount of RMR energy requirements that the ISO's estimates will not be scheduled in the Day Ahead market (*87 FERC ¶ 61,208 1999* (May 26, 1999). However, since different buyers cannot co-ordinate the quantity each of these Market Participants purchases in the Day Ahead market, the amount of total aggregate demand that may be shifted out of the Day Ahead market in response to this information can only be imperfect at best.

The increased need to decrement other generation that is committed in the Day Ahead market represents a significant source of market distortion and inefficiency created by current RMR dispatch protocols. When units are committed in the Day Ahead market as part of balanced schedules, but are not needed due to unscheduled RMR energy appearing in real time, overall market inefficiency is reduced in several ways. Unit commitment and scheduling are likely to be less optimal, reducing overall generation efficiency. In addition, alternative transactions – representing economic use of this generation – may be prevented.

2.1.3 Increased Ancillary Service Costs

The ISO must defend against real time load uncertainty and volatility by procuring ancillary services. Regulation, which accounts for about 80% of the ISO's ancillary service costs, is procured based on the ISO's determination of how much upward and downward Regulation capacity is needed during different hours to manage load fluctuations. By increasing the volatility of real time system imbalances, unscheduled RMR energy (along with other factors affecting real time demand) increases the amount of Regulation the ISO must purchase to manage load fluctuations, and imposes unnecessary costs on demand met through the ISO system.

2.1.4 Reliability Risks

By increasing the uncertainty and volatility of real time load imbalances, allowing RMR energy to "spill over" into real time unscheduled against demand ultimately creates increased risks relating to system reliability. Increased purchases or ancillary services can reduce, but not eliminate, the potential impacts of system load imbalances on system reliability in the event of different contingencies.

2.2 Indirect Market Impacts

In addition to directly impacting the ISO's real time imbalance market, current RMR dispatch protocols indirectly affect the PX Day Ahead energy market in two ways:

- Causing the purchase of excess supply in the Day Ahead market which is not needed to meet demand; and
- Providing an incentive for RMR owners to refrain from scheduling RMR units in the Day Ahead market when the Variable Cost Payment they can receive under the RMR contract path is greater than the PX MCP.

The following sections outline the market distortions and inefficiencies created in the Day Ahead energy market by these indirect impacts of current RMR protocols.

2.2.1 Overpurchase of Supply in Day Ahead Market

Current RMR protocols are inconsistent with the fact that RMR generation is *must-run* and must ultimately be used to meet demand. Figures 1 through 4 illustrate the impacts of this key market design flaw on prices in the Day Ahead market.

Figure 1 shows how RMR energy, which is *must-run* and must ultimately be used to meet demand, may not be scheduled against demand in the Day Ahead market under current procedures. In Figure 1, RMR generation hypotethically bid at $35 does not clear the Day Ahead market. Under current ISO protocols, this excess supply "spills over" into the real time imbalance market, where supplier D (whose $30 bid set the MCP) may be decremented to balance supply and demand in real time.

Figure 2 shows how purchasing the excess supply (represented by supplier D) increases the PX price, in relation to the MCP that results when all RMR generation is scheduled against demand in the Day Ahead market in recognition of the fact that this RMR energy is "must-run" and must ultimately be used to meet demand. In this example, a variety of market distortions and inefficiencies result from not "netting out" RMR generation from the Day Ahead market:

- Since the resulting MCP of $30 does not reflect the actual bid price of the marginal suppler ($25), an inefficient price signal is sent to potential buyers and suppliers.
- From the perspective of buyers, the $30 MCP discourages potential additional demand that may exist from entering the market at prices between the observed MCP of $30 and the $25 bid price of the marginal non-RMR supply actually needed to meet existing demand.
- From the perspective of suppliers, the $30 MCP provides an incentive for additional supply to enter the market based this $30 price signal, even though the bid price of the marginal non-RMR supply actually needed to meet demand is only $25.

In addition to creating market distortions and inefficiencies, the higher MCP created by the inclusion of demand that must ultimately be met by RMR generation 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.

Figure 3 illustrates how correct price signals can be sent to both suppliers and buyers by "netting out" the 500 MW RMR generation from demand, and allowing this residual demand to be met through the competitive Day Ahead market. When the 500 MW of demand that must be met by RMR generation is subtracted from overall demand, the MCP of $25 reflects the actual cost (or bid) of the marginal supplier. No incentive is provided for additional suppliers to enter the broader market with bids between $25 to $30.

Figure 4 illustrates how treating RMR as must-take generation through zero priced bids in the PX results in the same outcome as "netting out" an equal amount of demand from the Day Ahead market. This has exactly the same effect as "netting out" the amount of demand that must be met by the RMR unit from the overall market, but accomplishes this within the existing market structure more efficiently and with the least potential disruption.

Figure 1. Current RMR dispatch protocols ignore the fact that RMR energy must ultimately be used to meet demand

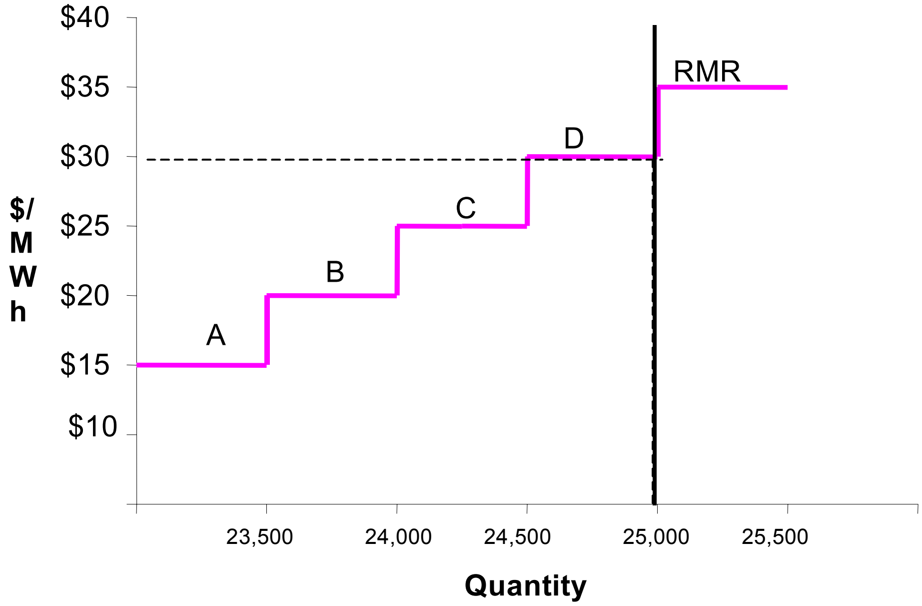


Figure 2. Purchasing excess supply to meet demand that must be met by RMR results in a MCP set by generation not needed to meet demand

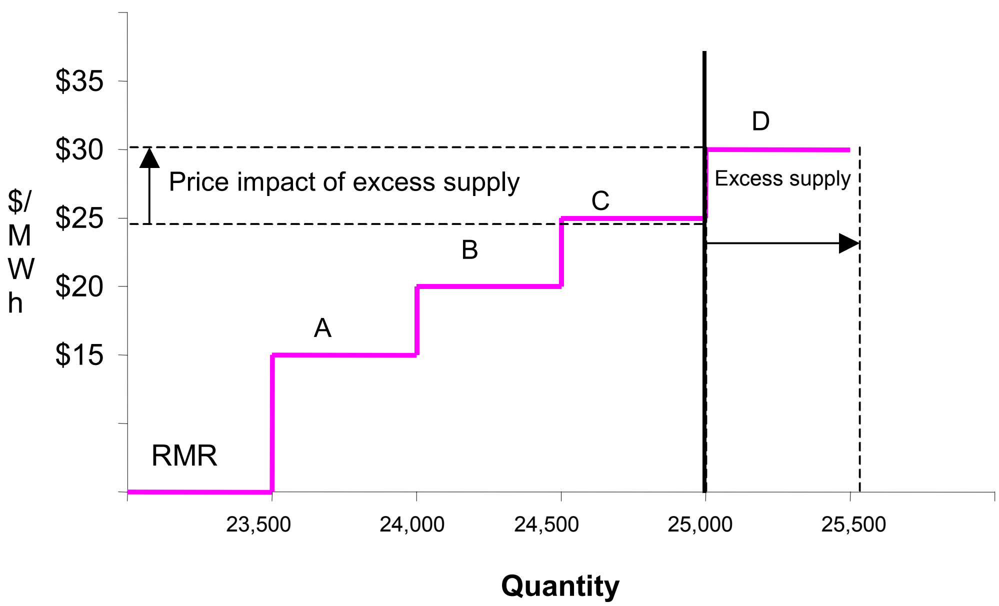


Figure 3 With RMR generation "netted out" of Day Ahead demand, MCP equals the bid price of the marginal supplier needed to meet demand

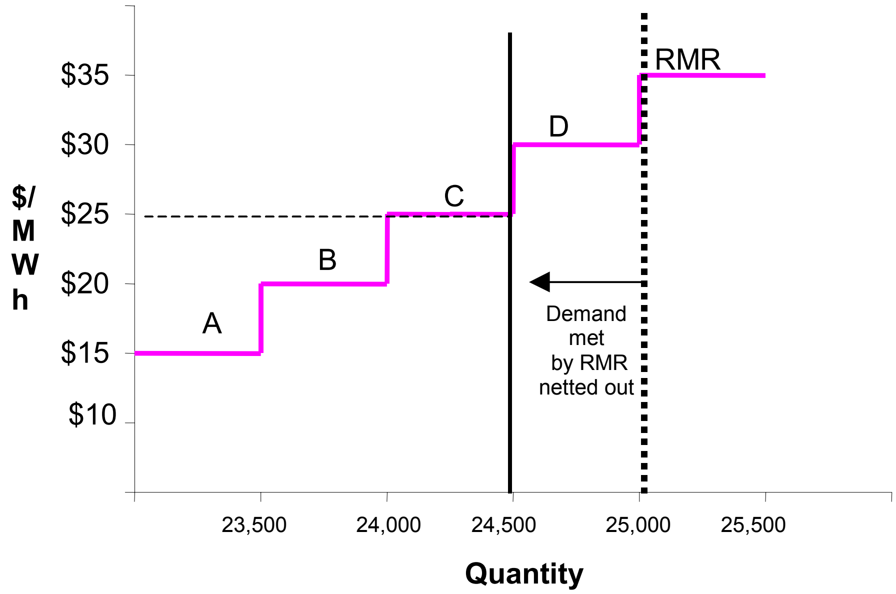
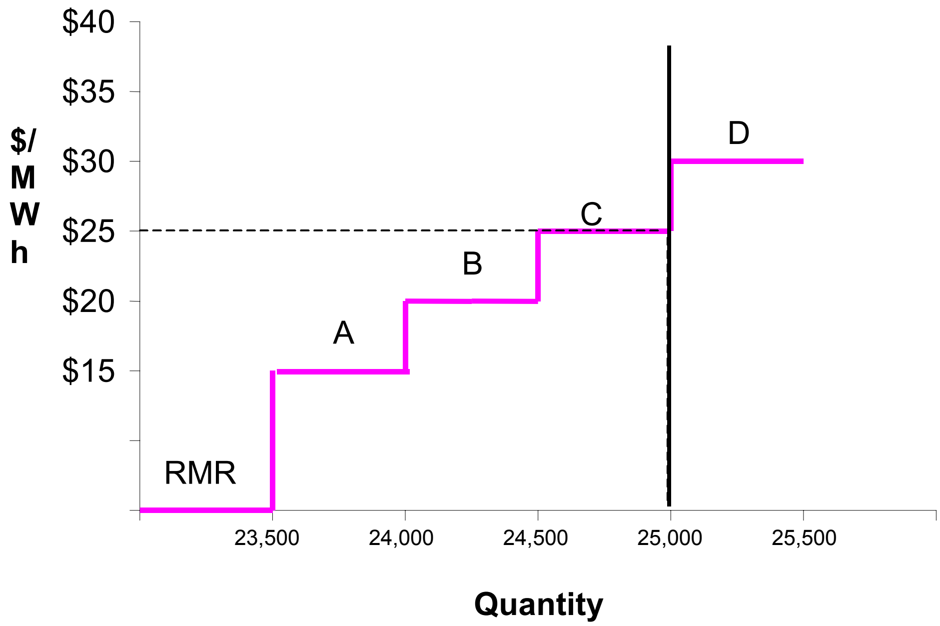


Figure 4 Bidding RMR as must-run in the Day Ahead PX market nets out RMR supply from demand, and results in MCP equal to bid price of marginal supplier needed to meet actual demand

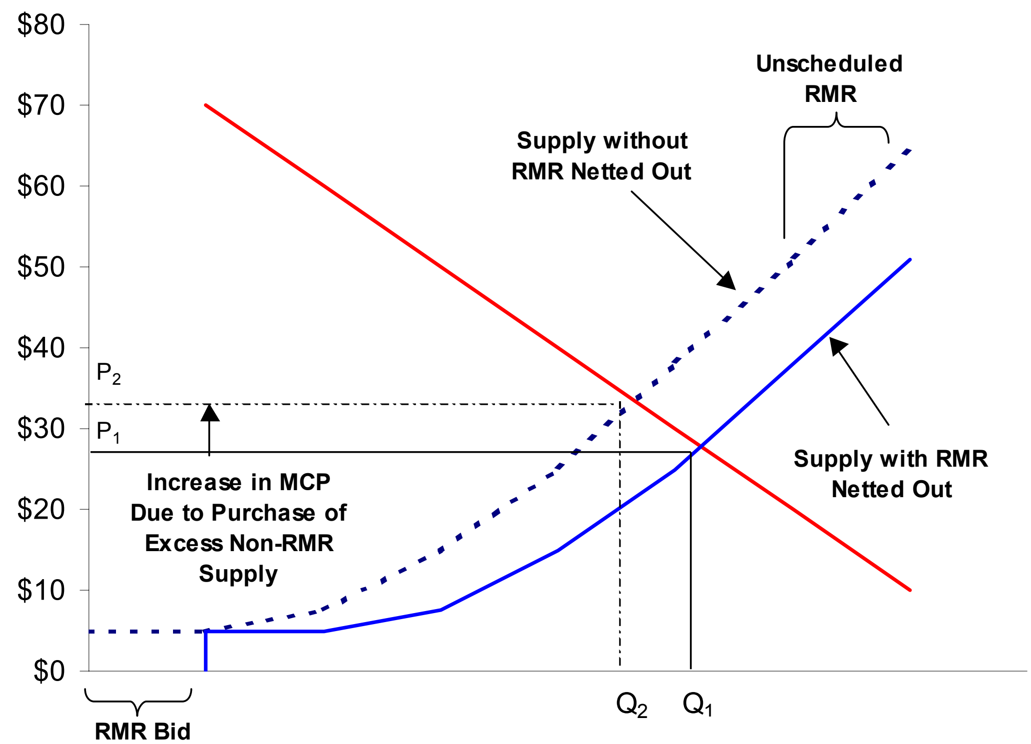


For simplicity, the previous example depicts demand in the Day ahead market as inelastic between the points of the demand curve intersected by the supply curve with and without RMR generation under the contract path being treated as "must-run" in the Day ahead PX market (as represented by the vertical demand curve in Figures 3 through 6). In practice, demand in the Day Ahead PX is somewhat elastic, largely due to the ability of buyers to shift demand into the ISO's real time market. When elasticity of demand due to the ability to shift demand into the real time market is considered, it can be shown that current protocols still result not only in an overpurchase of supply in the PX, but also increase demand in the real time market.

Figure 5 illustrates the effect of current protocols when demand is highly elastic in the Day Ahead market, but simply shifts any demand not scheduled in the Day Ahead market to the real time imbalance market. In this example, without RMR netted out of the Day Ahead market, the MCP is higher, and the amount of load scheduled in the Day Ahead market is lower ($Q_1 > Q_2$). In practice, most (if not all) of the reduction in load scheduled in the Day ahead markets "shifted" into real time. However, unless demand is perfectly elastic (i.e., the demand curve is horizontal), this shift in demand is less than the amount of RMR generation netted out of Day Ahead demand ($Q_1 - Q_2 <$ RMR). Thus, the impact of not netting out RMR is only *partially* offset by the elasticity of demand bids in the PX market, with the following results:

1. The MCP is inflated by the inclusion of demand that must be met by RMR generation, and
2. Demand in the real time market is increased, due to the need to meet additional demand not met in the PX Day Ahead market.

Figure 5. Impact of Not Netting Out RMR Generation from Demand



2.2.2 Withholding of Capacity from Day Ahead Market

New RMR contracts taking effect in June 1999 removed the major incentives to withhold capacity (or bid uncompetitively high prices) in Day Ahead market created by the Reliability Payment of the contract A and the credit back provisions of contract B.[8] However, under the new RMR contracts, the Variable Cost Payment received by RMR units called after the Day Ahead market still provides an incentive for RMR unit owners to refrain from schedule RMR capacity in the Day Ahead market during many off-peak and shoulder hours when (1) units must continue to operate at minimum levels due to operational constraints, and (2) the PX MCP is lower than the unit's VCP.

One of the key features of California's market design is that both energy and ancillary services are traded and scheduled on an hourly basis, with each hour representing a different market period. In practice, however, due to start-up costs, minimum run times and other operational constraints, thermal generation units (other than CTs) cannot choose to operate in the energy market on an hour-by-hour basis. Instead, units are "committed" to the market based on start-up costs and on overall price trends, and are then operated in a manner that maximizes net operating revenues on an hour-to-hour basis (ignoring start-up expenses that represent "sunk" costs).

In the absence of RMR contracts, thermal generating units which are already started up and on-line must often continue to operate during hours when market prices fall below their variable operating cost. Net operating revenues can typically be maximized during these hours by ramping units down to minimum operating levels, and utilizing market revenues from this generation to minimize the "loss" of needing to continue operating during these hours.

Under current RMR protocols, however, RMR unit owners being dispatched by the ISO after the Day Ahead market receive payment for full variable costs of operating at their minimum reliability level. During hours when this Variable Cost Payment exceeds the PX MCP, RMR owners can maximize revenues by not scheduling RMR units which they expect will be called by the ISO in the Day Ahead market.

Figure 6 provides an illustration of how current RMR dispatch protocols, combined with the VCP received by generators selecting the contract path after being dispatched by the ISO, can encourage RMR unit owners not to schedule RMR units in the Day ahead market during hours when market prices are lower than their variable cost payments. Analysis of historical operating data presented in the following section support the theoretical example presented in Figure 6.

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[8] See "Report on Impacts of RMR Contracts on Market Performance," prepared by the Market Surveillance Unit (currently Department of Market Analysis), California Independent System Operator (March, 1999), included as Attachment E to the transmittal letter of the ISO's filing for the tariff changes which are the subject of this report .

Figure 6. Do New RMR Contracts Still Encourage Withholding of Capacity from the Day Ahead Market?

The following example illustrates how the Variable Cost Payment provided under Condition 1 of the new RMR contract in effect since June 1999 still provides an incentive for RMR owners to refrain from scheduling capacity in the Day Ahead market. Without an RMR contract, the unit in this example would have an incentive to schedule the energy it produces at its minimum operating level in the Day Ahead market even during hours when the PX price was lower than the unit's variable operating costs. Due to start-up costs and minimum run times of most RMR thermal units, overall revenues would be maximized by ramping units down to their minimal operating level and being a price taker in the Day Ahead market during these hours. In this example, if the unit's 20 MW RMR requirement can be predicted with a high level of certainty, operating revenues are maximized by not scheduling any energy in the Day Ahead market during hours when the PX MCP is lower than the unit's variable costs. This enables the RMR unit owner to get reimbursed for full operating costs, rather than the lower market energy price during these hours. In this example, being able to select this contract option increases net daily revenues from $3,040 to $5,000, but decreases the amount of RMR capacity that would be scheduled to meet demand in the PX market. The situation illustrated in this example can be avoided by pre-dispatching RMR requirements and treating RMR generation being provided under the contract path as must-run in the Day Ahead market.

			Without RMR		**With Condition 1 of Interim Settlement**		
Hour	Unit VC	PX	PX Energy (MW)	Net Daily Revenue	PX Energy (MW)	Net Daily Revenue	Decrease in MW Bid < MCP
1	$40	$32	20	-$160			20
2	$40	$30	20	-$200			20
3	$40	$28	20	-$240			20
4	$40	$26	20	-$280			20
5	$40	$28	20	-$240			20
6	$40	$30	20	-$200			20
7	$40	$32	20	-$160			20
8	$40	$34	20	-$120			20
9	$40	$36	20	-$80			20
10	$40	$38	20	-$40			20
11	$40	$40	20	$0			20
12	$40	$42	100	$200	100	$200	
13	$40	$44	100	$400	100	$400	
14	$40	$46	100	$600	100	$600	
15	$40	$48	100	$800	100	$800	
16	$40	$50	100	$1,000	100	$1,000	
17	$40	$48	100	$800	100	$800	
18	$40	$46	100	$600	100	$600	
19	$40	$44	100	$400	100	$400	
20	$40	$42	100	$200	100	$200	
21	$40	$40	20	$0			20
22	$40	$38	20	-$40			20
23	$40	$36	20	-$80			20
24	$40	$34	20	-$120			20
				$3,040		$5,000	

Unit Capacity	= 100 MW	Minimum Operating Level	= 20 MW
Variable Operating Cost	= $40/MW	Minimum Operating Time	= 24 hours
RMR Requirement	= 20 MW		

Proposed tariff modifications would still allow RMR owners to benefit by having the option to receive the VCP during these hours, and select the market path during hours when the market prices were expected to exceed the variable operating costs. However, since energy being provided under the contract path would be scheduled in the Day Ahead market, this capacity, which must be generating due to operation constraints, would not be withheld from the Day Ahead market.

3. Analysis of Market Impacts of RMR Dispatch Protocols

This section examines the direct and indirect impacts of modifying current RMR protocols based on analysis of data from the PX and ISO's energy markets. Only three months of data are available for the period since new RMR contracts took effect (June through August, 1999). Prior to June 1999, incentives created by the payment provisions of previous RMR contracts introduced additional sources of market distortions and inefficiencies that are believed to have influenced the operation of RMR units, as well as the overall performance of California's energy markets. In addition, as noted in Section 1, a variety of market design features and flaws have been identified that have had an even more significant impact on market performance and trends than RMR dispatch protocols. Within this framework, the following analysis is designed to provide a quantitative indication of the magnitude of the direct and indirect impacts that modifications in RMR dispatch protocols may have on California's energy markets.

3.1 Direct Impacts

Figure 7 compares the average total RMR requirements to the amount of RMR generation that was not scheduled in the Day Ahead market on an hourly basis for the three month period since new RMR contracts have been in effect (June to August 1999). As shown in Figure 7, an average of about 500 to 700 MW of RMR energy has appeared in real time unscheduled against demand over this time period.

One of the best indicators of the inefficiencies created when RMR energy is not scheduled against demand is the amount of RMR energy appearing in real time that requires the ISO to decrement other generating units scheduled against load in the forward markets. Figure 8 shows portion of RMR requirements that required the ISO to decrement scheduled generation in real time in order to balance loads and generation for each of the 17 months since the ISO began operation. Over this 17-month period, about 25% of RMR dispatched after the Day Ahead market has had to be accommodated by decrementing energy from scheduled generation in real time. As shown in Figure 8, since new RMR contracts took effect in June of this year, the ISO has continued to need to decrement significant amounts of scheduled generation to accommodate RMR energy appearing in real time unscheduled against demand. Over the three-month period from June to August 1999, over 27% of RMR energy provided under the contract path of the new contract created the need to decrement other generation in real time.

As noted in Section 1 of this report, a variety of market design features and flaws have been identified which have tended to create demand for incremental energy in the real time market. As the ISO implements software and market design modifications designed to reduce excessive imbalances between loads and generation in real time, an increasing portion of RMR dispatched after the Day Ahead market may need to be met by decremental energy bids of scheduled generation.

Figure 7. Average RMR Requirements by Hour (June – August, 1999)

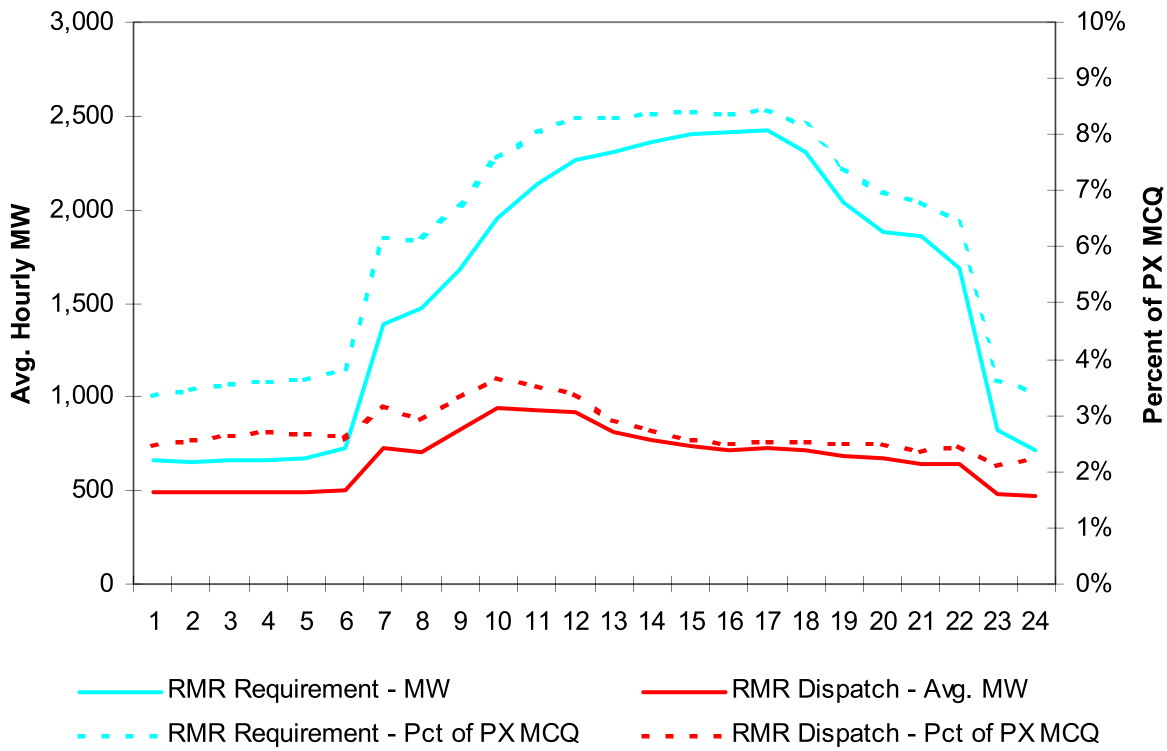
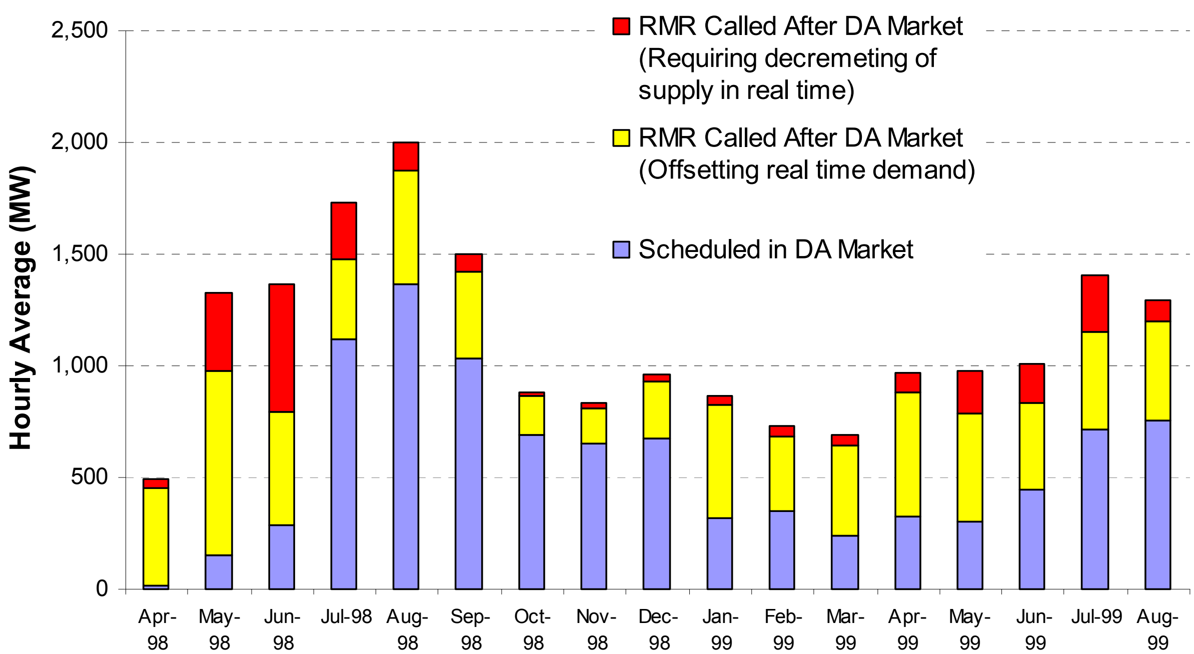


Figure 7 shows average RMR requirements by hour for the three month period, from June through August, 1999, since new RMR contracts have been in effect. The upper two lines show total RMR requirements, in terms of total MW (solid line) and as a percentage of total system load (dotted line). The lower two lines show RMR requirements that were not met through Day ahead schedules submitted to the ISO, requiring the ISO to issue a Schedule Change after the Day ahead market. This generation appeared unscheduled against demand in real time. With *pre-dispatch* of total RMR requirements and *netting out* of RMR generation which RMR unit owners opt to provide under the contract path, an average of about 500 to 700 MW of RMR generation under would have been "netted out" of demand in the Day Ahead market due to the requirement that RMR generation being provided under the contract path be bid in the PX Day Ahead market as "must-take" at a price of zero. As shown above, RMR generation under the contract path has represented an average of about 2 to 3% of the total market clearing quantity in the PX day ahead market.

Figure 8. Average Hourly RMR Requirements by Month



The top portion of each bar in Figure 8 shows portion of monthly RMR requirements that required the ISO to decrement scheduled generation in real time in order to balance loads and generation. Over the 17 month period since the ISO has been in operation, about 25% of RMR dispatched after the Day Ahead market has had to be met by decremental energy from scheduled generation in real time. As noted in Section 1 of this report, a variety of market design features and flaws have been identified which have tended to create demand for incremental energy in the real time market. As the ISO implements software and market design modifications designed to reduce excessive imbalances between loads and generation in real time, an increasing portion of RMR dispatched after the Day Ahead market may need to be met by decremental energy bids of scheduled generation.

3.2 Indirect Market Impacts

3.2.1 Background

Table 1 compares Day Ahead PX prices with the ISO's real time imbalance price on a monthly basis since California's restructured energy markets began operation in April 1998. As shown in this table, significant and systematic differences in prices have existed in these two markets during both peak and off-peak periods for extended periods of time. Closer examination of differences in the PX and real time prices on a day-to-day, week-to-week basis also indicates that the ability of Market Participants to arbitrage differences in these markets has often been limited and very imperfect. This suggests that the impacts of current RMR dispatch protocols on markets are likely to only be partially offset by shifts in aggregate market demand or supply between the Day Ahead and real time markets.

Table 1. Comparison of Average PX Day Ahead and Real Time Prices Monthly Averages, Peak and Off-Peak

	Peak Hours (7-22)			Off-Peak Hours (1-6,23-24)			All Hours (1-24)		
	PX Day Ahead	ISO Real Time	Percent Difference	PX Day Ahead	ISO Real Time	Percent Difference	PX Day Ahead	ISO Real Time	Percent Difference
Apr 998	$27.08	$27.24	1%	$18.63	$16.53	(11%)	$23.21	$22.33	(4%)
May	$14.99	$12.51	(17%)	$7.69	$5.51	(28%)	$11.65	$9.30	(20%)
June	$16.92	$11.69	(31%)	$6.39	$4.48	(30%)	$12.09	$8.38	(31%)
July	$40.79	$37.69	(8%)	$22.52	$15.97	(29%)	$32.42	$27.73	(14%)
Aug	$50.79	$59.93	18%	$26.21	$28.22	8%	$39.53	$45.40	15%
Sept	$40.97	$49.21	20%	$25.78	$30.80	19%	$34.01	$40.77	20%
Oct	$29.65	$36.82	24%	$23.11	$33.50	45%	$26.65	$35.30	32%
Nov	$28.60	$31.99	12%	$22.37	$28.91	29%	$25.74	$30.58	19%
Dec	$31.45	$32.26	3%	$26.39	$26.43	0%	$29.13	$29.59	2%
Jan 1999	$23.73	$22.13	(7%)	$17.68	$17.03	(4%)	$20.96	$19.79	(6%)
Feb	$21.70	$22.14	2%	$15.88	$15.24	(4%)	$19.03	$18.98	0%
Mar	$21.52	$23.77	10%	$15.83	$16.08	2%	$18.91	$20.24	7%
April	$26.92	$28.74	7%	$20.57	$21.48	4%	$24.01	$25.42	6%
May	$28.06	$22.59	(20%)	$18.36	$16.20	(12%)	$23.61	$19.66	(17%)
June	$30.56	$29.91	(2%)	$15.21	$12.84	(16%)	$23.52	$22.09	(6%)
July	$36.57	$31.33	(14%)	$19.88	$11.40	(43%)	$28.92	$22.20	(23%)
Aug	$39.83	$45.72	15%	$23.43	$25.25	8%	$32.31	$36.34	12%

Numbers in parentheses indicate percentage difference in price for months when average PX prices > real time prices. Real time prices based on prices for zone NP15.

Prices over the first 17 months of operation suggest that a seasonal trend may exist in the price differentials in these two markets. In 1998 and 1999, prices in the PX market have tended to exceed real time prices during months May through July. During these months, loads are relatively low, while significant quantities of hydro power are available. By August, however, real time prices have tended to exceed PX prices in each of the ISO's first two years of operation. By this time of year, less generation is available from hydro resources, and loads tend to hit summer peak levels with increased frequency. In the ISO's first year of operation, average real time prices continued to exceed PX prices through the fall months. Prices in these two markets tracked very closely from the end of November 1998 through April 1999, when the ISO began its second year of operation. As described above, prices in the first five months of this second year of operation have followed the same pattern, which occurred during these same months of 1998.

3.2.2 Overpurchase of Supply in Day Ahead Market

This section presents analysis of indirect impacts of RMR dispatch protocols using two approaches. First, hourly supply and demand bid data were used to simulate prices with RMR generation netted out of demand in the Day Ahead market. Results of this market simulation are compared to actual historical prices to assess potential distortions in market prices and overall costs caused by current RMR dispatch protocols. In addition, regression analysis was used to statistically estimate the impact of current dispatch protocols on price differences in the Day Ahead and real time markets over the summer 1999 period. Results from both of these analytical approaches are compared in terms of the estimated impact that current dispatch protocols have had on average prices in the PX and real time markets.

3.2.2.1 Simulation of Market Prices with RMR Generation Netted Out of Day Ahead Market

The potential impact of current RMR dispatch protocols on the Day Ahead and real time markets was assessed by simulating several scenarios, representing the potential market outcomes if all RMR generation were scheduled in the Day Ahead market. To assess these scenarios, the impact of proposed modifications in the RMR dispatch protocols on market clearing prices in the PX Day Ahead and ISO's real time markets were simulated on an hourly basis using actual bid data for the 12 month period from September 1998 to August 1999. Portfolio bid data were used for the PX market, while real time imbalance energy bids and quantities were used to simulate the ISO's real time market.

In simulating market prices of different RMR dispatch scenarios, it was assumed that the level of combined demand met in the PX Day Ahead and real time markets in each hour was inelastic, so that the sum of demand met in both markets in each simulated scenario equaled the sum of actual demand met these markets during each hour *t,* as summarized in the following equation.

Total Demand $_t$ = PX Market Clearing Quantity$_t$
+ Real Time Imbalance Energy$_t$ (incremental or decremental)
+ Demand met by RMR generation not scheduled against demand $_t$

With this approach, demand needing to be met in the real time market under each market simulation scenario was adjusted to account for any changes in demand met through the PX market due to the price effects of netting out RMR generation from the PX market.

To assess the magnitude of the impacts that RMR dispatch protocols may have on market prices and costs, three scenarios were examined:

1) **Without Pre-Dispatch and Scheduling of RMR in Day Ahead Market.** This scenario was developed by re-calculating PX and real time market clearing prices and quantities using actual bid data. The occurrence of only minor discrepancies between simulation results and actual market outcomes indicates that the computer routines developed by DMA to perform this analysis accurately reproduce market outcomes based on historical bid data.

2) **With Pre-Dispatch and Scheduling of RMR in Day Ahead Market.** This scenario represents simulated market outcomes if RMR generation that was historically dispatched by the ISO after the Day Ahead market had been directly netted out of the PX market (bid as must-take at a price of zero). In effect, this scenario represents market outcomes if this supply were shifted from the real time market to the PX market, as depicted in Figure 9 (sub-figures 3 and 4) on the following page. Since this scenario assumes that no change in the demand (or supply) bids into the PX market in response to market prices, results of this scenario represent the upper range of the potential impacts that current dispatch protocols may have on market prices and in terms of increased market costs.

3) **Pre-Dispatch of RMR with Increase in PX Demand from Reduced Underscheduling of Loads.** This scenario reflects the assumption that some, but not all, of the impacts of RMR dispatch protocols may be offset by a shifting of demand between the PX to the real time market. Price trends in the PX and ISO's real time markets indicate that although prices in these markets track closely over the longer term periods, systematic price differences have persisted in these two markets for sustained periods of time. This suggests that any adjustment of prices (back toward the historical level of observed prices) would be imperfect and incomplete. In this scenario, the imperfect ability of the PX and real time markets to equilibrate is simulated based on the extent to which demand could increase in the PX Day Ahead market if Market Participants scheduled loads based on forecasted demand, and did not seek to "shift" demand to the real time market by under-scheduling of loads. For this scenario, the potential shift in demand was estimated for each hour based on the amount of intentional under-scheduling that may have occurred in the overall market. The level of intentional under-scheduling that has occurred was estimated by taking the difference between the ISO's Day Ahead forecast and the amount of load scheduled in final Hour Ahead schedules. Figure 9 and the accompanying text describes the assumptions used in this scenario in more detail

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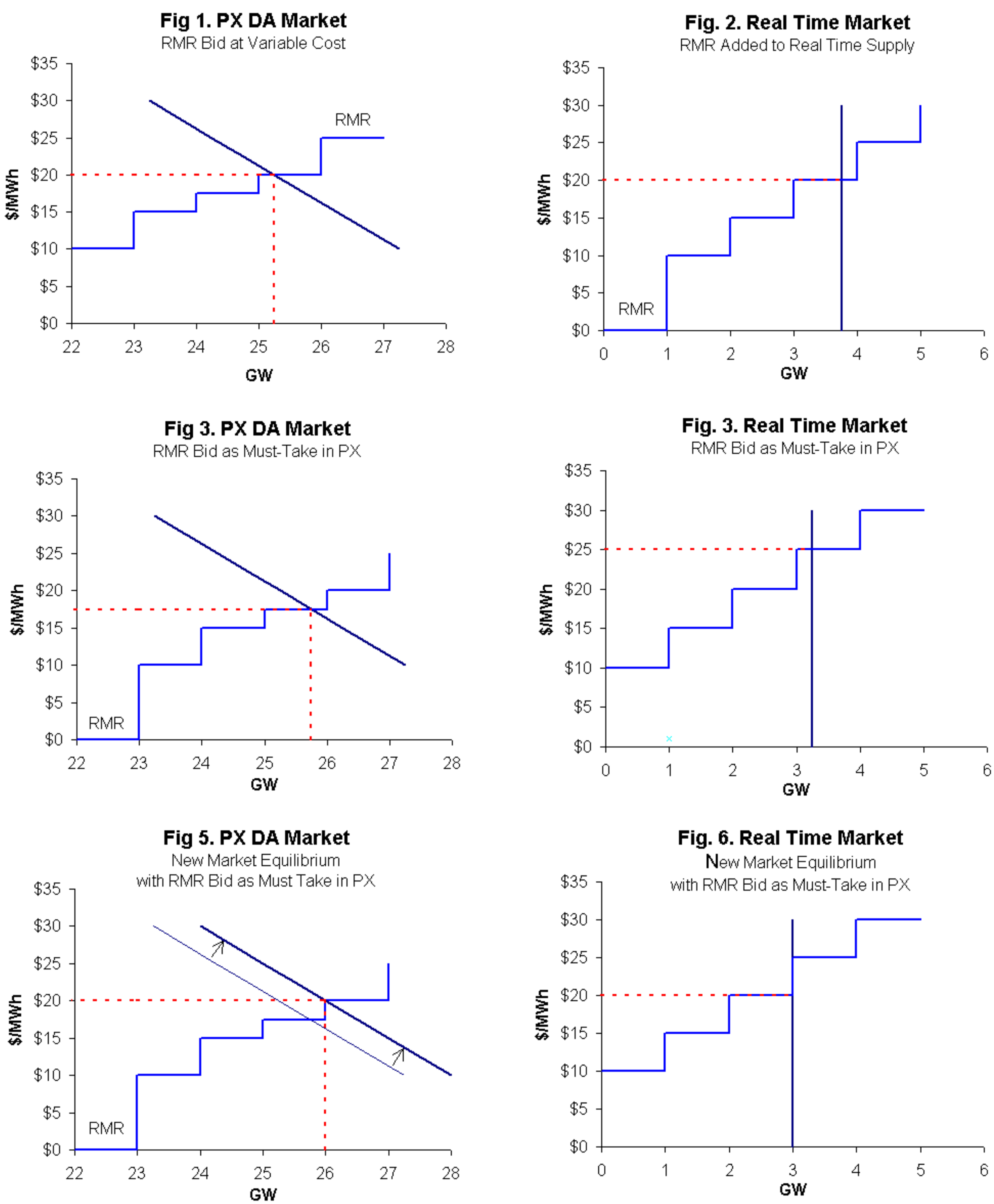
Figure 9. Analytical Framework of RMR Pre-Dispatch Market Simulation



Description of Analytical Framework in Figure 9

Figure 9 on the previous page depicts the analytical framework of this analysis (see sub-figures labeled Figure 1 through 6). Figures 9-1 and 9-2 depict the Day Ahead and real time markets during a single hour. For sake of illustration, this example assumes that historical prices in these two markets happen to be equal despite a variety of factors – including RMR dispatch protocols – which have tended to distort prices in these two markets. In practice, it should be noted that real time prices have often tended to exceed PX prices when significant demand for energy existed in the real time market (despite current RMR dispatch protocols). We believe this is due to a variety of factors which may have had a more significant effect on prices in these two markets during different time periods, such as the billing of Ancillary Service costs based on scheduled loads rather than actual real time demand.

As depicted in Figure 9-1, a significant portion of RMR requirements must be met by generation that is not scheduled in the Day Ahead market. Figure 9-2 depicts how RMR generation dispatched after the Day Ahead market ultimately increases the supply of energy in the real time market. During many off-peak and even peak hours, real time demand is less than the amount of extra supply created due to operating schedule changes issued to ensure RMR requirements are met, so that other non-RMR units must be decremented. However, Figure 9-2 depicts a typical peak period, when the extra supply created by RMR is in effect, used to "net out" demand from the real time market.

Figure 9-3 illustrates how treating all RMR requirements as must-take resources in the PX Day Ahead market could reduce market clearing prices by effectively shifting the supply bid into the PX. In many cases, this may also increase the real time price, due to the resulting reduction in the "supply" of must take resources in the real time market, as depicted in Figure 9-4. In this example, for instance, a drop in the PX price from $20 to $17.50 would be accompanied by an increase in the real time price from $20 to $25.

One of the key characteristics of California's marketplace is that demand is free to "shift" into real time in response to prices in the PX market. This helps to allow prices in the two markets to equilibrate as buyers respond to this price differential by shifting additional demand from the real time market to the Day Ahead market. Thus, if prices were significantly lower in the PX due to netting out of RMR generation, demand in the PX market may shift, so that prices in the two markets were closer. In theory, this shift could cause relative prices in the two markets to reach the same level as was historically observed with netting out of RMR generation, as depicted in Figure 9-5 and 9- 6.

It is important to note that this framework does not incorporate any additional changes in the bidding behavior of suppliers that may result from the requirement that RMR units be treated as must-run in the PX market. Proposed bidding rules for RMR units do not require that generators simply "shift" their supply curves by adding an additional segment of capacity (priced at zero) that is equal to their RMR contract requirement. Thus, if simply shifting the supply curve in the manner depicted in Figure 9-3 would result in profits that are insufficient to cover fixed costs of current capacity and new supply required meet demand growth, suppliers could be expected to increase bid prices for supply bids setting the market clearing price.

Figure 10. Pre-Dispatch of RMR and Potential Increase in PX Demand from Reduced Under-Scheduling in Day Ahead Market

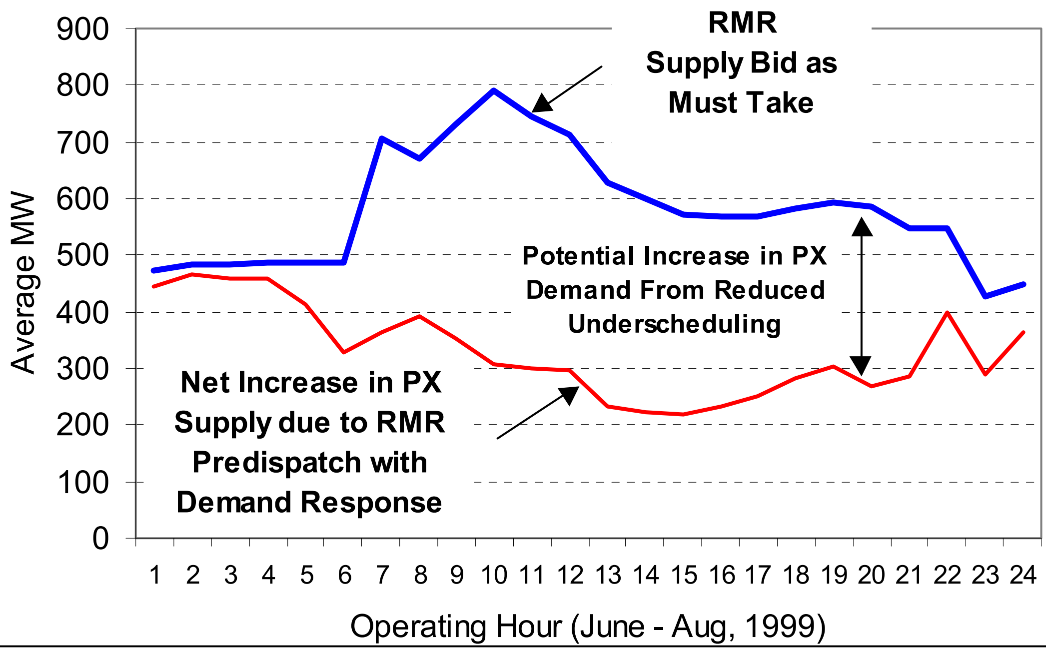


Figure 10 illustrates the scenario used to assess the potential impacts of RMR netting out, taking into account the potential demand response, or reduced under-scheduling of load in the Day Ahead market. The upper line shows the average hourly amount of RMR generation dispatched after the Day Ahead market that would have been netted out of the Day Ahead market under the proposed tariff changes. The lower line represents the net change in PX supply, taking into consideration a potential shift in demand due to a reduction in intentional under-scheduling in the Day Ahead market.

To develop this scenario, the amount of intentional under-scheduling (if any) was first estimated by taking the difference between the ISO system's Final Hour Ahead Schedule and the ISO system's Day Ahead Forecast (which is used in this analyis to represent load expectations at the time of the PX market). If forecasted loads exceeded scheduled loads, this was assumed to be the amount of intentional *under-scheduling* by Market Participants. Otherwise, no intentional under-scheduling was assumed.

The potential shift in demand to the real time market due to current RMR dispatch protocols was then estimated based on the amount of intentional under-scheduling (if any) which occurred. When the amount of underschedulng that occurred exceeded the amount of RMR generation not scheduled in the Day Ahead market, it was assumed that the shift in demand from under-scheduling would exactly offset (but not exceed) the amount of RMR generation not scheduled in the Day Ahead market. During these hours, simulation results yield the same market clearing prices as were observed historically, as depicted in Figure 9 on page 23 (see sub-figures 5 and 6). Otherwise, RMR generation bid as must-take in the PX is partially offset by the shift in demand, resulting in lower PX prices and higher real time prices.

The potential shift in demand due to under-scheduling was limited in this way (i.e., to be *no greater* than the additional amount of RMR generation that would be netted out of PX demand) in order to avoid simulation outcomes in which PX prices *increased* relative to actual observed prices due to netting out. This assumption reflects the fact that under-scheduling is caused by others factors unrelated to RMR generation, and that buyers would not have any incentive to reduce under-scheduling to the point where PX prices were higher than were historically observed.

Results of the different scenarios examined in this analysis are presented in Table 2 below. The upper bound of market impacts (represented by the difference in total PX and real time market costs *with* and *without* netting out) are estimated to be as high as $273 million based on data for 12 month period from September 1998 to August 1999. Under the assumptions used to represent the potential increase in PX demand due to reduced underscheduling, total market impacts are estimated to be as high as $110 million based on data for this 12 month period.

Table 2. Market Simulation Results – Pre-Dispatch and Neting Out of RMR
With and Without Increase in PX Demand from Reduced Underscheduling

	Pre-dispatch of RMR Without Demand Response		Pre-dispatch of RMR With Demand Response	
	Difference in Market Costs (Millions)	Percent of Total Energy Market Costs*	Difference in Market Costs (Millions)	Percent of Total Energy Market Costs*
Sept 1998	$20	2.7%	$6	.8%
Oct	$11	2.2%	$5	1.0%
Nov	$11	2.5%	$6	1.3%
Dec	$20	3.9%	$5	1.0%
Jan 1999	$16	4.5%	$6	1.7%
Feb	$7	2.8%	$2	.7%
March	$19	6.3%	$12	3.8%
April	$21	5.6%	$11	2.8%
May	$32	8.3%	$12	3.1%
June	$29	6.6%	$11	2.6%
July	$56	8.6%	$23	3.6%
Aug	$32	4.3%	$13	1.7%
Totals	$273	4.8%	$110	2.0%

* *Reduction in total PX and real time market costs due to netting out as a percentage of total PX plus real time market cost.*

The following section compares results of these market simulations with statistical estimates of the impact of RMR dispatch protocols on prices in these two markets.

3.2.2.2 Regression Analysis

This section presents results of statistical analysis of the impact of RMR dispatch protocols on prices in the PX Day Ahead and real time markets. For this analysis, the difference between prices in the Day Ahead PX market and the real time price for each operating hour was first defined as follows:

$PRICE\_DIF_t$ = PX Day Ahead MCP_t – Real $Time_t$

Regression analysis was then used to assess the impact of different factors on the difference in prices in these two markets. Variables used in the regression model include the amount of RMR dispatched after Day Ahead market, as well as variables representing a variety of other factors that would be expected to significantly effect differences in the Day Ahead and real time price. The model was estimated based on the three-month period from June to August 1999, during which new RMR contract payment provisions were in effect.
The following variables were used in the final model[9]:

RMR_MW_t = Total MW of RMR dispatched after Day Ahead market, which appeared unscheduled against demand in real time. This does not include any RMR dispatched in real time for intra-zonal congestion.

ACT_LOAD_t = Actual hourly ISO system loads (in GW).

ACT_LOAD2_t = Actual hourly ISO system loads (in GW) squared. This variable was included to capture how prices in the real time market have tended to exceed PX Day Ahead market at high load levels, particularly above 40,000 MW.

$FCST\_ERR_t$ = This variable represents the impact of unexpected loads in the real time market due to forecast errors. Higher than expected loads would be expected to increase the real time price relative to prices in the Day Ahead market (resulting in a negative regression coefficient, given the specification of the dependent variable in the model). The variable representing forecast error used in the model was calculated by taking the difference between actual ISO system loads and the ISO's final Day Ahead Forecast developed prior to the Day Ahead market for each operating hour of the following operating day (Actual Loads – Final Day Ahead Forecast).

$UNDER\_SCH_t$= This variable represents the market price impacts of intentional under-scheduling (rather than under-scheduling due to forecast errors). Under-scheduling would also be expected to increase the real time price relative to prices in the Day Ahead market (resulting in a negative regression coefficient, given the specification of the dependent variable in the model). Intentional under-scheduling was on the difference between actual ISO system loads and

[9] Additional analysis was performed to assess the impact of enhancing the model with additional variables from data that is not publicly available, including the amount of energy scheduled as *Regulatory Must-Run* and *Must-Take*. Although these variables were found to have a significant impact, their inclusion in the model had a negligible impact on the overall model and on the co-efficient for RMR dispatched after the Day Ahead market. As a result, these were not included in the final model in order to limit the model variables generated from publicly available data.

the ISO's final Day Ahead Forecast developed prior to the Day Ahead market for each operating hour of the following operating day (Actual loads – Final Hour Ahead Schedule).

$WEEKEND_t$ = An indicator variable (0/1) representing weekend days. One for weekends; zero for weekdays.

$PEAK_t$ = An indicator variable (0/1) representing peak versus off-peak hours. One for peak hours (7-22); zero for all off-peak hours (1-6,23-24).

JULY_99 = An indicator variable (0/1) representing all hours during the month of July 1999.

AUG_99 = An indicator variable (0/1) representing all hours during the month of August 1999.

Regression model results of this analysis are summarized in Table 3. All variables in the model (with the exception of the variable representing peak hours) were found to have a significant impact on the difference between the PX Day Ahead and real time markets (p >.95). Variables with *negative* co-efficients represent factors tending to cause the real time price to *exceed* the Day Ahead price. These include periods of very high loads (ACT_LOAD2), when actual load exceeds the Day Ahead forecast (FCST_ERR), and when actual load exceeds the hour ahead Schedules (UNDER_SCH).

Table 3. Regression Model Results
June to August, 1999

Variable	Co-efficient	t-statistic
RMR_MW	.00665	3.24
ACT_LOAD	14.14242	15.55
ACT_LOAD2	- .24810	-16.91
FCST_ERR	- .01013	-20.48
UNDER_SCH	- .00834	-13.37
PEAK_HR	- .44024	- .22
WEEKEND	- 3.71866	-2.54
JULY_99	2.89083	1.92
AUGUST_99	- 4.68335	-3.16

Model R-squared = .33

With this model formulation, the coefficient for RMR_MW_t variable represents the impact of RMR energy on the *difference* in the PX and real time price (PX MCP – Real Time Price) in dollars per MW of RMR energy dispatched after the Day Ahead market. The positive sign of this co-efficient indicates that RMR energy dispatched after the Day Ahead market tends to *increase* the difference between the PX Day Ahead and real time price. It should be noted this represents a *relative* increase in the PX price compared to the real time price, which may result from a combination of *increased* PX prices and *decreased* real time prices.

Regression model results cannot be used to directly estimate the extent to which RMR dispatch protocols may *increase* in the PX price and *decrease* the real time price. In practice, this could vary from hour to hour, depending on the slopes of the supply and demand curves in the Day Ahead and real time market. The following section describes how regression results can be combined with market simulation results — which reflect the relative slopes of the PX and real time supply curves each hour — to estimate the total impact of RMR dispatch protocols on total market costs.

3.2.2.3 Comparison of Market Simulation and Regression Results

For sake of comparison with market simulation results, regression results can be used to calculate the average hourly difference in the PX Day Ahead MCP and the real time price by multiplying the regression co-efficient by the average amount of RMR dispatched after the Day Ahead market (580 MW) over the three month period (June to August 1999). As shown below, this calculation indicates that RMR dispatched after the Day Ahead market has increased the PX prices relative to the real time price by an average of about $3.89 per MW.

.0067 $/MW x 580 MW = $3.89/MW

Table 4 summarizes simulation results in terms of the total net impact of RMR dispatch protocols on the total *difference* between the prices in both the PX Day Ahead and real time prices. For instance, simulation indicate that if all RMR were netted out the PX Day ahead market, the average PX price would have been about $2.00 *lower*, while the average real time price would have been about $3.28 *higher,* representing a total difference of $5.28 per MWh in prices in these two markets during the summer 1999 period. Under the scenario which assumes an increase in PX demand due to reduced under-scheduling, simulation results indicate that the average PX price would have been about $1.22 *lower*, while the average real time price would have been about $2.02 *higher,* representing a total difference in price of $3.24 per MWh over the summer 1999 period. Results of each simulation scenario indicate that the increase in PX prices represents about 38% of the total difference in PX and real time prices due to current RMR dispatch protocols costs, with decreased real time prices accounting for about 62% of the impact of RMR on the price differential in these two markets.

When presented in this format, simulation results can be directly compared to statistical estimates of the impact RMR dispatch protocols on the difference in prices in these two markets. As shown in Table 4, simulation results for the June through August 1999 period indicate that the net impact of current dispatch protocols is to increase the difference between the PX Day Ahead and real time prices by $3.24 to $5.28 per MWh. This compares to the statistical estimate of $3.89 per MWh over these months. Thus, statistical analysis supports the conclusion that the actual impacts of current RMR dispatch protocols may fall within the range of results for the two market simulation scenarios. Statistical results are most consistent with results of the market simulation scenario that assumes a demand response from reduced under-scheduling in the Day Ahead market due to pre-dispatch and scheduling of all RMR in the Day Ahead market.

Table 4. Difference in Average PX Day Ahead and Real Time Prices With and Without RMR Pre-Dispatch and Scheduling in Day Ahead Market

Market ***Simulation Scenario: RMR Pre-dispatch (no demand response)***

	PX Day Ahead	Real Time	Total Difference
Without RMR Netted Out	$28.30	$26.88	
With RMR Netted Out	$26.30	$30.16	
Price Difference	$ 2.00	($ 3.28)	$ 5.28
Percent of Total Difference	38%	62%	

Market Simulation Scenario: RMR Pre-dispatch with Reduced Under-Scheduling in Day Ahead Market

	PX Day Ahead	Real Time	Total Difference
Without RMR Netted Out	$28.30	$26.88	
With RMR Netted Out	$27.98	$28.90	
Price Difference	$ 1.22	($ 2.02)	$ 3.24
Percent of Total Difference	38%	62%	

Regression results can also be combined with market simulation results — which reflect the relative slopes of the PX and real time supply and demand curves each hour — to estimate the total impact of RMR dispatch protocols on total market costs. With this approach, hourly simulation results are first used only to estimate the *percentage* of the total change in the difference between the PX and real time prices that result from a change in the PX price in each hour *t*:

$\Delta\, PX_t$ = Simulated PX MCP with RMR Pre-dispatch $_t$ - Actual PX MCP_t

$\Delta\, RT_t$ = Simulated Real Time Price with RMR Pre-dispatch $_t$ - Actual RT $Price_t$

$\Delta\, Total_t = \Delta\, PX_t - \Delta\, RT_t$

$$\text{Percent } \Delta\, PX_t = \frac{\Delta\, PX_t}{\Delta Total_t}$$

Similarly, the *percentage* of the total change in the difference between the PX and real time prices that would result from a change in the real time price in each hour *t* can be estimated as follows:

$$\text{Percent } \Delta\, RT_t = \frac{\Delta\, RT_t}{}$$

$$\Delta \text{ Total}_t$$

These hourly percentages (which reflect the actual slopes of the supply curves in the PX and real time markets each hour), can than be combined with the statistical estimate of the impact of RMR dispatch protocols on the difference in market prices each hours as follows.

First, amount of RMR dispatched after the Day Ahead market each hour is multiplied by the regression co-efficient representing the estimated of the impact of RMR dispatch protocols on the difference between the PX and real time price (.0067 \$/MW):

$$\Delta \text{ RMR}_t = \text{RMR MW}_t \times .0067 \text{ \$/MW}$$

This represents the statistical estimate of the total increase in the difference between the PX and real time price due to RMR dispatch protocols in each hour. This statistical estimate can be disaggregated using the hourly price change factors derived from simulation results:

$$\Delta \text{ PX}'_t = \Delta \text{ RMR}_t \times \text{Percent } \Delta \text{ PX}_t$$

$$\Delta \text{ RT}'_t = \Delta \text{ RMR}_t \times \text{Percent } \Delta \text{ RT}_t$$

The impact of modifying RMR dispatch protocols on total market costs can then be approximated by multiplying the estimated change in market prices by the total quantities in each market:[10]

$$\Delta \text{ Market Costs}_t = (\Delta \text{ PX}'_t \times \text{ PX Quantity}_t) + (\Delta \text{ RT}'_t \times \text{ Real Time Quantity}_t)$$

Table 5 compares this method of approximating the impact of RMR dispatch protocols on market costs to results of the market simulation which assumes a demand response from reduced under-scheduling in the Day Ahead market. As shown in Table 5, results of both approaches provide highly consistent estimates of the impacts of RMR dispatch protocols over the summer 1999 period. Results based on regression analysis indicate that current RMR dispatch protocols account for an increase in total markets costs of about \$56 million over the three month period from June through August 1999. This estimate is about 20% higher than the market simulation scenario which assumed that the impacts of RMR pre-dispatch would be offset in part by a significant increase in PX demand due to reduced under-scheduling in the Day ahead market. As shown in Table 2, results of this market scenario indicate that on an annual basis, RMR dispatch protocols may increase total wholesale market energy costs by as much as \$110 million per year.

Thus, this comparison of statistical and market simulation supports the conclusion that the impacts of current RMR dispatch protocols introduce

[10] This simplified approach underestimates the reduction in total market costs since the amount of energy purchased in the PX Day Ahead market with RMR pre-dispatch would be greater than the actual amount purchased due to the elasticity of demand in the Day Ahead market.

significant distortions in the Day Ahead market, which increase total wholesale market energy costs by as much as $110 million per year.

Table 5. Comparison of Market Simulation and Regression Model Results

Millions of Dollars in Total Market Costs, June though August, 1999*

	RMR Pre-dispatch With increase in PX demand from reduced under-scheduling in DA market	Regression Results With ratio of change in PX and real time price based on hourly simulation results
June	$11	$ 9
July	$23	$29
Aug	$13	$19
Totals	$47	$56

** Figures represent increase in total market costs (in millions) due to current dispatch protocols.*

3.2.3 Withholding of Capacity from Day Ahead Market

3.2.3.1 Illustrative Case Study

Figure 11 presents an empirical example – taken from actual operating records for an RMR unit in July 1999 – which illustrates how the VCP provided to units under Condition 1 of the new RMR contracts provides an incentive for RMR operators to refrain from scheduling RMR units in the Day Ahead market during hours when units must continue operating, but the PX MCP is lower than a unit's VCP.[11] The RMR unit in this example was called under RMR the previous day, and could continue to run profitably on this day with or without being called under their RMR contract (as shown in Figure 11). The unit's operating characteristics require that it operate at a minimum level of 20 MW even during hours when the PX price was lower than its variable costs. Without an RMR contract, the owner could have maximized net operating revenues by scheduling the unit in the Day Ahead market during these hours. With the RMR contract, however, operating revenues are maximized by not scheduling the unit in the Day Ahead market when the PX MCP is lower than the VCP it receives under the RMR contract path. In this case, the unit's net operating revenues under this strategy were increased about 4% from $49,00 to $51,000.

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[11] As a case study, the example also provides an empirical example of the hypothetical case presented in Section 2 (Figure 6), which was included in previous testimony submitted by the ISO in conjunction with the partial RMR contract settlement in April 1999.

Figure 11. Case Study Example of Impact of Variable Cost Payment on RMR Owners Incentive to Schedule Energy in the Day Ahead Market

RMR Unit Characteristics

Maximum Capacity	320 MW	Startup Time	10 hours
Minimum Capacity	20 MW	Minimum Run Time	24 hours
Variable Cost Payment	$28/MWh		

		Actual Operating Schedule and Revenues With RMR Contract Variable Cost Payment				Optimal Schedule and Revenues Without RMR VCP		
Hour	PX MCP	DA Energy Schedule	Minimum Reliability Requirement	Schedule Change	Net Revenues	MW	Net Revenue	Net Difference (MW)
1	$19.19	0	20	20	$0	20	($176)	-20
2	$14.00	0	20	20	$0	20	($280)	-20
3	$13.99	0	20	20	$0	20	($280)	-20
4	$11.25	0	20	20	$0	20	($335)	-20
5	$13.99	0	20	20	$0	20	($280)	-20
6	$14.00	0	20	20	$0	20	($280)	-20
7	$15.00	0	70	70	$0	20	($260)	-20
8	$26.00	0	70	70	$0	20	($40)	-20
9	$26.74	0	70	70	$0	20	($25)	-20
10	$29.99	0	70	70	$0	20	$40	-20
11	$31.00	91	70	0	$273	91	$273	0
12	$31.01	226	70	0	$680	226	$680	0
13	$39.99	320	70	0	$3,837	320	$3,837	0
14	$45.81	320	70	0	$5,699	320	$5,699	0
15	$52.94	320	70	0	$7,981	320	$7,981	0
16	$60.53	320	70	0	$10,410	320	$10,410	0
17	$54.81	320	70	0	$8,579	320	$8,579	0
18	$50.00	320	70	0	$7,040	320	$7,040	0
19	$41.85	315	70	0	$4,363	315	$4,363	0
20	$33.01	293	70	0	$1,468	293	$1,468	0
21	$33.00	204	70	0	$1,020	204	$1,020	0
22	$30.76	0	70	70	$193	70	$193	-70
23	$26.88	0	20	20	$0	20	($22)	-20
24	$22.00	0	20	20	$0	20	($120)	-20
					$51,543		$49,483	

In addition to situation illustrated above, the VCP may also impact the resource portfolio bidding and scheduling strategies of RMR owners, in that this payment serves as a "backstop" payment for any RMR requirements not scheduled in the Day Ahead market. For instance, this payment reduces the potential opportunity cost for generators bidding their resource portfolio into the PX above their variable costs in order to increase market clearing prices. Under such bidding strategies, even if the RMR owners are not awarded enough capacity in the Day Ahead market to schedule RMR units which are on-line and must continue generating at some level, the ability to receive payment for the full variable operating costs of these units reduces the trade-off between higher market prices and lower market sales that such bidding strategies typically create for generators.

3.2.3.2 Analysis of Withholding of Capacity in Day Ahead Market

Capacity that may have been withheld from being scheduled in the Day Ahead market due to the ability of RMR to receive the Variable Cost Payment when called under RMR was assessed on unit-by-unit basis using the following methodology:

- Only thermal units with start-up times of 8 hours or more were used in the analysis. Other units (quick-start CTs and hydro units) were excluded since they typically do not face the operating constraints requiring them to run at minimum load when market prices drop below their operating costs.
- If a unit had a Day Ahead schedule indicating it was operating and "in the market" during any hour of the day, it was assumed that these units were committed to be in operation the entire day (due to the start-up costs and times necessary to start the thermal units included in this analysis).
- For days when each unit was scheduled in the Day Ahead market, it was assumed that each unit would need to continue operating at its minimum operating level, even during hours when the PX MCP was less than the unit's VCP.
- Each unit's VCP was compared to the PX Day Ahead price, to identify units with operating costs greater than and less than the PX MCP.
- Results of this unit-by-unit analysis of hourly data were then summed up to calculate the overall portion of RMR requirements not scheduled in the Day Ahead market which appear to have been economic to schedule in the Day Ahead market (due to the need of these thermal units to continue operating at minimum levels, or PX prices exceeding the variable operating costs of units already committed to be started up and in operation).

As shown in Figure 12, results of this analysis indicate that a total of about 29% of RMR requirements not scheduled in the Day Ahead market appear to have been economic to schedule. About 16% of RMR requirements not scheduled represent energy during hours when the PX MCP was less than the VCP these units receive if called under RMR. Another 13% of RMR requirements were not scheduled in the Day Ahead market even though these thermal units were on-line, and the hourly PX MCP exceeded the unit's VCP. As noted above, this may be attributable to owners bidding into the PX above the variable costs of their resource portfolio, who are not awarded enough capacity to schedule all capacity with variable costs lower than the

MCP. In such situations, the VCP would logically be factored into owners' portfolio scheduling decisions. Figure 13 summarizes results of this same analysis by operating hour.

Figure 12. RMR Requirements Not Scheduled in Day Ahead Market By Thermal Units On-line, With Minimum Operating Levels

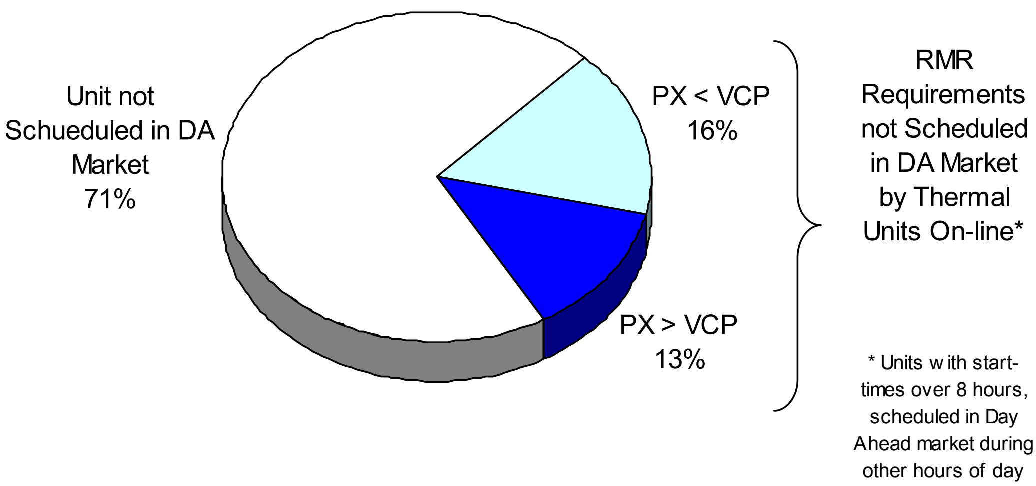
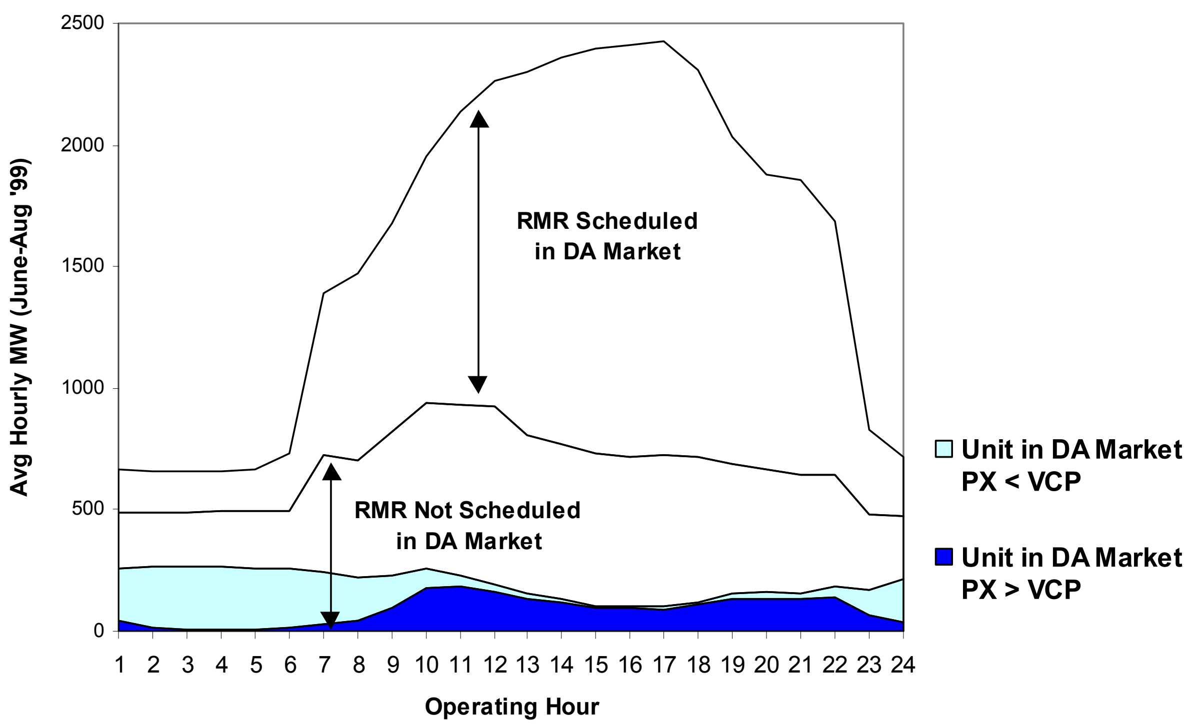


Figure 13. RMR Requirements Not Scheduled in Day Ahead Market By Thermal Units On-line, With Minimum Operating Levels



3.3 Summary and Conclusions

By requiring that energy from RMR units that is needed for local reliability appears in real time unscheduled against demand, current RMR dispatch protocols directly decrease overall supply efficiency by increasing the need to *decrement* in real time other units with generation schedules. At the same time, the anticipation of unscheduled RMR energy "spilling over" into real time may create an incentive for buyers to attempt to take advantage of this "must take" generation by shifting a portion of demand to the real time markets. Due to the inability of buyers to forecast perfectly this supply of RMR energy and co-ordinate any shift in demand to the real time market, any such shift in demand is likely to be imperfect and thereby add unnecessary volatility to real time market demand and prices. This further decreases overall supply efficiency by reducing the ability of generation operators to optimally commit and schedule portfolios of supply resources based on expected load conditions and price signals in the Day Ahead and Hour Ahead markets. By increasing the volatility of demand in the real time market, current RMR dispatch protocols also require that the ISO purchase additional Ancillary Services to manage this volatility, and ultimately increase the risk to system reliability created by real time energy imbalances.

The ISO is continuing to implement a variety of measures to decrease or eliminate features of the California market design that have created highly volatile, often excessive demand for both incremental and decremental energy in the ISO's real time market. The DMA believes that the proposed modifications to RMR dispatch protocols represent one of the most important components of this overall market redesign effort. In combination, the ISO expects implementation of these measures to have significant direct benefits in terms of reduced market and system volatility, increased efficiency and reliability, and reduced Ancillary Service requirements costs. The DMA believes that the direct benefits alone would justify the proposed tariff changes.

In addition to these direct impacts, the DMA believes current RMR dispatch procedures impose even more significant costs on market efficiency and consumers due to the indirect effects of excess supply purchased in the PX market to meet demand that must ultimately be met by RMR generation. Precise quantification of these indirect impacts based on historical market data is difficult due to the ability of buyer and sellers to arbitrage between the Day Ahead markets, and the presence of a variety of different factors which have created distortions which hinder the ability for California's different energy markets to equilibrate. However, while some of the impact of current RMR dispatch protocols on the PX price could be offset by buyers "shifting" demand from the PX to the real time market by intentionally under-scheduling of loads, actual day-to-day price trends indicate that the ability of buyers to arbitrage between these two markets is very imperfect, as evidenced by significant and systematic price differences in these market for many periods of time. Therefore, we believe that economic theory and recent market performance support lead to the conclusion that RMR dispatch protocols introduce unnecessary inefficiencies and distortions to California's energy markets. Analysis presented in this report indicates that the potential magnitude of these indirect impacts are likely to be significant, and represent millions of dollars of total market costs.

New RMR contracts taking effect in June 1999 removed the major incentives to withhold capacity (or bid uncompetitively high prices) in Day Ahead market created by the payment provisions of RMR contracts. However, under current RMR dispatch protocols, the Variable Cost Payment received by RMR units called after the Day Ahead market still provides an incentive for RMR unit owners to refrain from scheduling RMR capacity in the Day Ahead market during many off-peak and shoulder hours when (1) units must continue to operate at minimum levels due to operational constraints, and (2) the PX MCP is lower than the unit's VCP. Analysis presented in this report indicates that a significant portion of RMR generation dispatched after the Day Ahead market would have been economical for RMR owners to schedule in the Day Ahead market in the absence of the VCP. Proposed modifications in RMR dispatch protocols would allow RMR owners to continue benefiting from the VCP by having the option of electing to be paid under the *contract path* when markets fall below the VCP but units need to continue generating due to operational constraints. However, with pre-dispatch and netting out of RMR under the contract path, market distortions created by the VCP would be avoided by ensuring that all generation being provided under the RMR contract path would be scheduled in the Day Ahead market.

Finally, it should be noted that the netting out of RMR generation prior to the Day Ahead market also brings the treatment of such generation into line with the basic design of the restructured California electricity markets. To implement the ISO's function of managing the grid independently of the energy markets, the ISO accepts only balanced schedules from Scheduling Coordinators. To be consistent with this principle, the energy acquired from RMR units to ensure local reliability, which can be determined and dispatched by the ISO just prior to the PX Day Ahead market, should be balanced against load in the Day Ahead or Hour Ahead market. If this is not done, then the aggregate of the Scheduling Coordinators' balanced schedules and the unsold RMR energy is unbalanced, forcing the ISO to address this situation in the real-time energy market, which was not designed for this purpose.

Attachment A:
Opinion of Prof. Robert Wilson

Date: December 3, 1998

To: Market Surveillance Unit, California ISO

From: Robert Wilson, Consultant

RE: Summary Report on RMR Procedures

1. RMR operations are purchased by the ISO to enhance grid reliability. The byproduct is an energy supply (not matched with any demand load) that the ISO purchases under the existing provisions of long-term contracts with generators. If this energy surplus spills over into the real-time market then the ISO must, in effect, resell this energy in the real-time balancing market.

   The basic organizing principle of the ISO's charter is that it manages the grid independently of the energy markets. This principle is implemented by accepting only balanced schedules from participating Scheduling Coordinators. In particular, the aggregate of the day-ahead schedules should be balanced.

   This principle implies that the energy acquired from RMR purchases, to the extent known and called before the PX day-ahead market opens at 7:00 a.m., should be offered as must-take supplies in the PX. (The PX is the relevant energy market since it is the only one that is fully transparent.) If this is not done then the aggregate of the Scheduling Coordinators' balanced schedules and the unsold RMR energy is unbalanced – and in effect, the ISO is thereby participating in the energy markets, contrary to the basic market design that separates the ISO's grid management from the energy markets.

   The RMR energy is must-take because there is no prospect of reducing its supply due to price considerations; i.e., like all other must-take supplies its opportunity cost is zero even though the variable cost of generation is positive.

2. RMR operations provide the public good of grid reliability for which the ISO is responsible. RMR operations and the energy byproduct are purchased outside the market, via contracts, because otherwise the local monopoly power of the generators would often enable them to demand prices above the market price that the ISO would be forced to accept to ensure grid reliability.

The important principle to guide the contract specifications is that the ISO must obtain the requisite RMR reliability services without impairing the competitiveness of the general market for energy. That is, the ISO's RMR purchases of operations and energy must decouple reliability management from the equalization of demand and supply in the much-larger competitive part of the energy market.

The Market Surveillance Unit's proposed contracts show that this can be accomplished if the RMR energy passes through the PX market as must-take. The must-take provision is required because otherwise the absence of any part of the RMR energy in the day-ahead market and its spillover into later markets would tend to raise day-ahead prices and lower real-time prices, which can be corrected only by elaborate arbitrage – such as UDC's withholding demands from the day-ahead market to real-time market – which would undermine the key design of the California markets in which most transactions are to be accomplished via balanced day-ahead schedules, and the real-time market is reserved for intra-zonal balancing (at the ISO's expense!).

3. Regardless of the strength of the present evidence pro or con that RMR contractors might be withholding RMR energy from the day-ahead markets to influence the market price obtained by other units in their portfolios, or to obtain the greater of the RMR price and the market price, the fact remains that the incentive to withhold poses a long-term risk of severe proportions that cannot be ignored. Eliminating this incentive by requiring called RMR energy to pass through the PX market as must-take is necessary to ensure decoupling of grid reliability operations from the competitive energy markets, and thereby to ensure the continued competitiveness of the energy markets. The Market Surveillance Unit's proposal to allow the RMR contractors to obtain the maximum of the market price and the RMR payment provides assurance that no RMR contractor is disadvantaged.

   Claims are reportedly made that treating RMR energy as must-take could lower the day-ahead price and thereby reduce the profitability of other units in an RMR contractor's portfolio. If this were true it would reflect incomplete arbitrage between the day-ahead and real-time prices, in which case the contractor could preserve its profitability by withholding some energy from the day-ahead market in order to obtain higher expected prices in the subsequent real-time market. The evidence is strong, however, that there is no systematic difference between the day-ahead and real-time prices, and there is no indication that any future scenario would entail a systematic divergence in prices. Therefore, I see no convincing evidence that contractors' profits on their other units will be reduced by the MSU's proposals.