Market Surveillance Committee of the

California Independent System Operator

Report on Redesign of Markets for Ancillary Services and Real-Time Energy

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March 25, 1999

EXECUTIVE SUMMARY

The Market Surveillance Committee (MSC) of the California Independent System Operator (ISO), as requested by the Federal Energy Regulatory Commission order of October 28, 1998, has conducted a further review of performance of the ISO's ancillary service markets. This report summarizes the analysis and recommendations that have been provided to the ISO since the MSC's preliminary report on the performance of ancillary services markets, submitted August 17, 1998.

This report reviews: (1) the ISO's proposal for redesigning the ancillary services markets, filed at FERC on March 1, 1999; (2) impact of the current the Reliability-Must-Run (RMR) contracts on the operation the PX and ISO markets as well as elements of the settlement proposal for new RMR contracts to be filed shortly; and (3) the issues associated with raising the ISO's "damage control" price caps on bids accepted in its ancillary services and real-time energy markets. The MSC's findings and conclusions are summarized below.

Ancillary Services Redesign: The Commission over the last nine months has eliminated cost-based rates for individual generators and has confirmed the ISO's authority to impose a damage control cap on ancillary services. The rational buyer protocol and other changes proposed in the ISO's March 1, 1999 market redesign filing are necessary for properly functioning ancillary services markets, and we recommend the Commission approve them with the modifications recommended in this report.

RMR Contracts: The MSC can express only preliminary views on the proposed settlement respecting the RMR contracts to be filed at FERC in the near future. The proposed settlement appears to be an important first step in the reformation of the contracts. However, full mitigation of certain perverse incentives created by the current RMR contracts also requires a second step, namely reversing the bid/call sequence and bidding RMR units as "must-run," a step that will not take effect under the proposed settlement until December 1, 1999, at the earliest. Accordingly, it is our view that until this second step has been effectuated, we cannot be confident that the ISO's markets will be workably competitive.

Price Caps: The Committee recommends that the ISO's authority to impose "damage control" caps on real-time energy and ancillary services be retained for the foreseeable future. However, the current $250 caps should be increased to $750 as soon as the March 1 market redesign proposals and both steps in the RMR reform process are implemented. The caps should be increased to $2500 as soon as a summer peak's experience shows that these changes are sufficient to ensure the market is workably competitive. The MSC intends to offer advice in the future indicating what observable markets conditions are indicative of workably competitive markets. Finally, we recommend that the ISO adopt polices designed to avoid lowering the caps -- once they have been raised -- except in the most compelling circumstances.

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I. INTRODUCTION

On July 9 and 13, 1998, prices on the California ISO's day-ahead auction market for replacement reserve peaked at $5000 and $9999 per MW, respectively. The ISO responded to these price spikes by unilaterally setting a maximum price of $500/MW at which it would purchase ancillary services; this maximum was later reduced to $250/MW. The $250 price cap remains in place today. On July 17, 1998, the FERC upheld the ISO's authority to impose such a price cap and, among other things, directed the Market Surveillance Committee (MSC) to conduct an independent review of the operation of the ISO's ancillary services markets and to report its findings and recommendations to the ISO and the Commission.[1] The MSC's report ("August MSC Report") was submitted to the ISO Board of Governors on August 19, 1998. The ISO made the report public and submitted it to the FERC on that date. The MSC report recommended that the ISO: (1) adopt a "rational buyer" protocol for purchasing ancillary services, (2) revise its reliability-must-run (RMR) contracts, (3) seek the elimination of generator-specific cost-based price caps for ancillary services, (4) retain a market-wide "damage control" price cap on ancillary services, (5) establish a state-wide auction for ancillary services; and (6) revise its scheduling and imbalance practices to reduce the need for regulation reserve.

The Commission, after comment, in an order issued on October 28, 1998, directed the ISO to file on March 1, 1999, a comprehensive proposal to redesign its ancillary services markets. The October 28th order also directed the MSC to prepare a final report to further clarify the causes of the market anomalies identified in its August preliminary report.

This report has been prepared in response to the Commission's October 28th order. It summarizes the findings of the Committee's August 19th report, and the further reports on the opinions the Committee has prepared and issued since its August 19th report. This report also makes a series of recommendations with respect to the operation of the auction markets that the ISO operates for ancillary services and real-time energy, as well as recommendations regarding the restructuring of the ISO's RMR contracts. This report also references the results of an analysis of the effects of the RMR contracts on California energy markets prepared by Frank Wolak, Chair of the MSC and James Bushnell. A preliminary version of that analysis was made available to market participants on December 7, 1998. In response to comments received from market participants and FERC staff, further analysis was performed by Frank Wolak and James Bushnell, the results of which are reported below in summary form. Also described below are a number of recommendations the Committee provided to the ISO with respect to price caps in the real-time market and the design of the "rational buyer protocol."

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[1] The Commission also directed the PX Market Monitoring Committee (MMC) to conduct a review of and prepare a report on the ISO's ancillary services markets. The MMC's report recommendations were generally consistent with the MSC's.

II. CALIFORNIA ENERGY AND ANCILLARY SERVICES MARKETS

California's restructured electricity markets give the ISO responsibility for operating, and ensuring the reliability of, the major part of the electric transmission grid in the State, and managing auction markets for real-time energy and for the following ancillary services: regulation reserve, spinning reserve, non-spinning reserve, and replacement reserve. The California Power Exchange (PX), which is independent of the ISO, operates auction markets for day-ahead and hour-ahead energy. In connection with its reliability responsibilities, the ISO also administers the RMR contracts under which it can call up to 110 in-state generating units to provide energy or ancillary services necessary to ensure the reliable operation of the California grid.

The four ISO ancillary services markets, the ISO real-time energy market, and the PX day-ahead and hour-ahead energy markets are largely served by the same generating units. In addition, most of the units under RMR contracts participate to some extent in both the ancillary services and energy markets. The result, as the MSC noted in its August report, is that the rules for pricing, bidding and settlement for any one market can affect the price and quantity bid into any of the other markets. In addition, a major determinant of price bid in one market is what that capacity could expect to earn in another market. Consequently, poorly designed markets that allow generators to earn inefficiently high prices creates high opportunity costs to participating in other markets that may be otherwise workably competitive. Generators then rationally bid higher prices into other markets because of these greater opportunity costs. Similarly, terms under which units can be called under the RMR contracts can potentially affect bidding behavior in any of the energy or ancillary services auction markets and scheduling behavior in the day-ahead energy market. This occurs because unit owners continually attempt to find the market where they earn the largest profit contribution (revenues in excess of operating cost) for their portfolio of generating units. During some periods of time, for some generating units, producing under the terms of the current RMR contract yields the highest total profit contribution for all units the generator owns.

Because generators continually attempt to find the markets with the highest prices in which to sell their energy and capacity, and because demanders continually attempt to find the markets with the lowest prices in which to purchase energy and ancillary services, all of the markets operated by the ISO and PX are highly inter-related. Therefore, the Committee's recommendations on market design encompass not only the ancillary services markets but also the real-time, day-ahead and hour-ahead energy markets, as well as the RMR contracts.

III. ANCILLARY SERVICES MARKETS

A. Performance of the ISO's Ancillary Services Markets

The capacity procured in the California ancillary service (ancillary services) markets is used to provide regulation reserve, spinning reserve, non-spinning reserve, and replacement reserve.

1. MSC Preliminary Report on Performance Through August 1998

In its August 1998 report, the MSC conducted a preliminary review of the operation of the ISO's ancillary services markets and offered recommendations for improving the performance of these markets. The MSC's August 1998 report is appended as Attachment A. The MSC recognized at the time that more definitive recommendations would have to await additional market experience and further data analysis.

The Committee found that the ISO's ancillary services markets were not yet operating in a manner consistent with workable competition. Prices in the ancillary services markets were not fluctuating in a manner that reflected changes in the underlying marginal costs of supplying these products. Ancillary services markets exhibited extreme price volatility, even during periods when demand was unchanged for long periods of time. In the Committee's opinion, the conditions were not yet in place to rely on these markets to set efficient, cost-reflective prices. Prices for lower quality services such as replacement reserve routinely exceeded the prices for higher quality services such as regulation. Often ancillary services capacity prices exceeded both the power exchange and real-time energy price for the same hour, despite the fact that no net energy need be produced to supply these ancillary services.[2] The Committee recommended that until workable competition was established, the ISO continue to utilize a price cap for ancillary services.

The Committee identified nine underlying factors that were then contributing to the inefficient operation of the ISO's ancillary services markets: (1) some firms were subject to cost-based price caps while others were allowed to earn market-based rates; (2) the demand for ancillary services was higher than anticipated; (3) the amount of each ancillary service demanded by the ISO did not depend on market prices and these demands were not procured in a rational manner; (4) perverse incentives for generator bidding and scheduling behavior were created by the RMR contracts; (5) the ISO often purchased ancillary services separately from small geographic areas, increasing the potential for the exercise of market power; (6) the ISO's dispatch practices were not transparent to market participants; (7) the allocation of ancillary services costs to scheduling coordinators was flawed; (8) suppliers of ancillary services from outside of the ISO control area were excluded from participation in these markets; and (9) the ISO's computer systems were still facing various software difficulties that were not yet fixed.

[2] Any allowable net energy supplied while providing these services is paid for at the real-time energy price.

While the Committee was not able to precisely measure the relative significance of each of these problems, its analyses did provide some insights. The quantities of ancillary service purchased far exceeded the levels at which they had historically been acquired. High demand was not a direct cause of the market irregularities, but the substantial quantities acquired appears to have increased the impact of the other factors. Prices for 'inferior' ancillary services routinely exceeded those for 'superior' services. The ISO's inability to substitute among these services therefore appeared to have significantly impacted the cost of acquiring them. Lastly, it appeared from the MSC's preliminary analysis that RMR contracts were not doing a great deal to reduce market power problems, and were most likely contributing to such problems by providing incentives for owners of generators with RMR units to bid and schedule their units less aggressively.

2. Market Performance Since August 1998

Our further review of the performance of the ISO's ancillary services markets bears out the observations we made in our August report.

a) Comparisons of the ISO Regime with Historical Experience

In the former vertically-integrated regulated utility environment, the total cost of ancillary services was approximately 3-5% of the total energy cost. The ISO's experience so far is that ancillary services comprise approximately 15% of the monthly energy cost.

There are two strong reasons to expect ancillary services to comprise a greater fraction of total energy costs in the ISO regime, even if that regime operated in perfectly competition fashion.

First, in the regulated regime, ancillary services were primarily provided by the vertically integrated utility to itself at the cost of providing these services. In contrast, in the ISO regime, ancillary services are purchased from the day-ahead and hour-ahead markets at market-clearing prices, which reflect the marginal cost of the highest priced unit necessary to supply this service. Under this regime the total cost of all ancillary services is total quantity purchased times this market-clearing price. In the vertically integrated regime the cost of ancillary services imputed by the IOU is the sum of the unit costs of each unit times the quantity supplied from that unit up to the highest cost unit necessary to supply the market. Consequently, even under conditions of marginal-cost bidding for ancillary services, total ancillary services "costs" under the market regime should be higher than those under the vertically integrated utility regime. If we eliminate the assumption of perfect competition in the ancillary services market, this cost difference between the two regimes becomes even larger.

Second, the vertically integrated utility had more options available to it than does the ISO to reduce the quantity demanded of each ancillary service. The vertically-integrated utility could look ahead throughout the day to determine the rate at which certain units should be shut down or brought up to maintain regulation as a zero net energy ancillary service. It could then order these units to shut down and come up at certain times and at certain energy levels, and the units, would, barring unforeseen contingencies, do so. In contrast, the California market design allows generators not providing regulation to produce energy at whatever rate they wish relative to their energy schedules, with the difference between their real-time production and hour-ahead energy schedules made up in the real-time energy market at the hourly real-time price. Because of the freedom generators have to deviate from their schedules in the California market design, the ISO may need to purchase more regulation and other ancillary services to guarantee against contingencies caused by generators being able deviate from their hour-ahead schedules in real-time.

b) Ancillary Services Costs

Figure 1a shows the breakdown of monthly ancillary services costs for 1998. Initially, a large fraction of these costs were paid to call RMR units to provide ancillary services. The major share of these RMR ancillary services costs paid for the energy necessary for the unit to provide that ancillary service. Most units were subject cost-based price caps on their ancillary service capacity payments and the energy was paid for at the "A Contract" variable payment rate, which includes a per unit fixed cost recovery factor. Figure 1b shows that the total amount of energy costs associated with calling RMR capacity to provide ancillary services declined to very small number by the end of September, with a few small spikes towards the end of December.

During the first three months of ISO operations (April through June, 1998), all ancillary services suppliers were subject to cost-based caps. Energy prices were not similarly regulated, as a result of which some suppliers could earn substantially more by selling energy at uncapped prices. Despite adequate capacity available to serve demand, there was a persistent bid insufficiency in the ISO's ancillary services markets. In response to these persistent bid shortages in Regulation capacity markets, the ISO adopted the Regulation Energy Price Adjustment (REPA) on May 21, 1998, which paid all suppliers of Regulation capacity an adder which was equal to the maximum of the *ex post* real-time energy price or $20/MW. While the REPA payments had the desired effect of attracting sufficient Regulation capacity to ensure reliable grid operations, they increased the total cost of Regulation from May to November. (The REPA payment was stopped on November 27, 1998, following the FERC's decision to grant market-based rates to all providers of ancillary services.) As shown in Figure 1a, REPA payments comprised the largest fraction of ancillary services costs during each month from July to November.

The combination of the REPA payment and the costs of purchasing regulation capacity was more than 50% of total monthly ancillary costs during June to December of 1998. In the months of October to December, regulation and REPA payments were significantly more than 70% of total ancillary services costs. During the months of July and August, replacement reserve costs were the next highest fraction of total ancillary services costs. This is perhaps one of the more puzzling aspects of the behavior of the ancillary services markets, because all producers had a right to market-based prices in this market throughout this time period.

Figure 1c plots the daily total of hourly day-ahead energy schedules as “Daily Load,” as measured using the right-hand vertical axis. Figure 1c also plots the daily scheduled energy cost (which for each hour of the day is given by the California Power Exchange (PX) day-ahead market clearing price times total day-ahead energy scheduled for that hour), as measured using the left-hand vertical axis. The daily total ancillary services costs, as plotted in Figure 1b, is reproduced here for comparison to daily energy costs.

Figure 1d plots by total daily ancillary services costs as a percentage of total daily scheduled energy costs. This graph shows that particularly during the months of May to August, ancillary services costs were a significant portion of total energy costs. From Figure 1c we can see that this percentage is high in May and early June because total daily energy costs were so low. However, in July and August both total daily energy costs and total daily ancillary services costs are large in absolute value, with total ancillary services costs more than 20% of total daily scheduled energy costs during many days.

On June 30, 1998, the FERC declared that Replacement reserve was not subject to cost-based caps, and granted market-based rate authority to several of the new (non-utility) owners of generating capacity. Many suppliers of the other ancillary services (Regulation, Spin, and Non-spin) remained under cost-based price caps. The uneven treatment of these markets may have led to defensive bidding in these markets by some IOUs who were now net buyers of such services. Under this strategy, net buyers of energy owning any generation capacity that could provide these ancillary services were presumed to bid this capacity in at low prices in an attempt to lower the market-clearing prices for ancillary services and therefore reduce their total ancillary services bill. Because Replacement reserve is the last market in the ancillary services sequential market clearing process, this strategy often led the lower-priced ancillary services capacity to be taken in an earlier market, resulting in bid insufficiency in the Replacement market despite its prevailing market based rates. Recall that during this period all of the IOUs were subject to cost-based bid caps for their bids into the three highest quality ancillary services markets. As loads increased during the season’s first major heat wave, shortages of bids, primarily in the Replacement Reserve market, resulted in total payments for ancillary services capacity as high as two-thirds of total energy costs on July 9th. In response to this crisis, the ISO imposed price caps on ancillary services capacity, which are discussed further below.

Even after the imposition of the price caps, the total costs of A/S capacity remained relatively high, generally accounting for over 10% of total energy costs through October. On October 28, 1998, FERC ordered the removal all cost-based rate caps on ancillary services. This order was put into effect on November 3, 1998. More recently ancillary services costs have been slightly lower; since January 1, 1999, ancillary services capacity costs have averaged about 9% of total energy costs. Ancillary services remain an expensive aspect of the operation of the California system. As shown in Figure 1a, even without the REPA payment in the month of December, regulation remains, by far, the highest-priced ancillary service. However, as will be discussed below, a number of reforms are underway which may substantially reduce the demand for regulation and improve the efficiency of California markets for ancillary services capacity.

c) Ancillary Services Prices

Figures 2a through 2l show the hourly ancillary services prices for regulation, spin, non-spin, and replacement reserves for each month from July to December for the NP15 and SP15 congestion zones. Similar to the August MSC Report, we truncate all prices at $250 and truncate all prices from below at zero, which means that prices above $250 are displayed as $250/MW and those below zero are displayed as zero. The latter constraint only effects the regulation market were firms submitted negative price bids in competing to receive the very high REPA payment when real-time energy prices where high. In December, negative prices for Regulation occurred because of the separate procurement of upward Regulation (RegUp) and downward Regulation (RegDn) at a single market-clearing price. Bidders submit negative bids on the side of market (RegUp or RegDn) they believe will not set the market-clearing price to gain a large market share of this lucrative market, but periodically bidders guess wrong, and this results in a negative price for regulation. All of the graphs also indicate the hours when all four ancillary services were procured zonally with a "+" at the top of the graph above that hour. This is the variable "Congestion" in the box at the bottom of the graphs. To aid interpreting these figures, Tables 1a and 1b give the monthly means and standard deviations of these hourly quantities for each month from June to December of 1998.

Since the August MSC Report was submitted, the prices for ancillary services have continued the pattern observed in the latter part of July throughout August and in the early part of September. Prices in all markets hit the ISO's price cap of $250 in all markets for many peak hours during this period. In addition, consistent with results reported in Figures 7 and 8 in the August MSC Report, prices in the intermediate range of greater than $50/MW and less than $150/MW were extremely rare, with the majority of prices below this value and a small, but a significant number of prices above this range in all four ancillary services markets. Even the Regulation market hit the $250/MW price cap for an number of hours during this time period, despite the fact that generators providing regulation were also receiving extremely large $/MW REPA payments because of very high prices in the real-time energy market.

The months of October and November were relatively placid in terms of the volatility of prices in the ancillary services markets. For example, in October the mean price of Non-Spin in the SP15 congestion zone was $0.63, with a standard deviation of $0.29, is a significantly lower mean price and standard deviation than in August when the mean was $37.98 and the standard deviation was $37.08. Although the price cap was hit a few times in the Regulation and Spin markets during this month, prices in the Non-Spin and Replacement reserve markets remained very low during this time period. This can be attributed in part to low levels of ISO system load during this period and corresponding low prices in the PX and real-time energy markets. Effective November 3, 1998 all providers of ancillary services were able to receive market-based prices for all four ancillary services. This could have also contributed to the low prices and reduced levels of volatility in the ancillary services markets during November. During this month, the

$250/MW price cap was only hit once. This occurred in the Regulation market. Prices above $150/MW occur during a few periods in the Spin market during October and November. A final factor contributing to the apparent improved performance of the four ancillary services markets is the fact threat of inter-zonal congestion during these months was such that during ancillary services were procured on a state-wide basis for all hours.

The pattern of prices during December is closer to those observed during the months of July to September than to October and November. There was significantly more price volatility in the Regulation market and the Spin markets than in October and November. The price of Non-Spin hit the bid-cap several times during this month. The only service that did not hit the price cap during the month was Replacement, which remained relatively low, apart from a few hours in the latter part of December when prices were in the range of $150/MW to $249/MW. Although Regulation did hit the $250/MW cap a few times during the month in the SP15 congestion zone, its price was significantly more volatile in other periods than it was in the previous two months. The average price of Regulation for the month also was significantly higher than in the previous two months.

There are two explanations for the December Regulation prices, both involving the REPA payment. First, effective November 27, the REPA payment was discontinued. From the graph of the price of Regulation on that day, we can see a pronounced discrete upward jump in the time path of prices. This is due to the fact that generators are no longer guaranteed the maximum of $20/MW and the real-time energy price in addition to the market price for Regulation capacity purchased through the market. Consequently, we would expect to see, and do indeed see, higher market-clearing regulation prices as a result. Furthermore, the volatility of Regulation prices previously increased because of volatility in the REPA payment, which varied with the real-time price of energy. Second, some of the volatility of prices in Regulation in recent months is attributable to the fact that since September 28, 1998, upward and downward Regulation have been procured as separate products, but with a single market clearing price, namely the higher of the two. As noted above, this provides an incentive for generators to try guess which side of the market sets the price, and bid extremely low (even negative) price to secure a large share of the Regulation market.

d) Ancillary Services Quantities

Figures 3a through 3l plot the hourly market requirements for all four ancillary services for each month from July to December for the NP15 and SP15 congestion zones. The variable "Congestion" denotes when these requirements were satisfied on a zonal basis. Except for Replacement reserve, there is a consistent within-day pattern of these requirements across days within each month. The very low and zero requirement levels for Replacement in mid-July were due to the price spikes in this market which triggered the FERC's request for the August MSC Report. With the exception of this time period, the ISO continued to procure Replacement in a manner that in many ways made it easier for market participants to set extremely high prices in the Replacement reserve market. In these months, all market participants knew that the ISO's requirement for Replacement was 500 MW in each congestion zone, regardless of the ISO load forecast for that hour.

During the peak load periods in the day we would expect the need for Replacement reserve to be significantly more than it is in the off-peak periods of the day. The August MSC Report recommended that the ISO adopt a strategy of setting its Replacement reserve requirements to follow this logic.

Beginning in the latter part of September, the ISO began to procure Replacement taking into account these considerations. In particular, the ISO's Replacement requirements from this point until the end of December were set to zero during the early morning hours of each day and increased to approximately 250MW in each zone during the peak hours of the day. Referring back to Figure 1a, one explanation for the fall in the total monthly cost of Replacement reserves from September to October is this Replacement Reserve procurement strategy. Further evidence for this explanation for the improvement in the behavior of prices in the Replacement reserve market is that the total costs of Replacement reserves continued to be a small fraction of total ancillary services costs during the months of November and December. Regulation reserve requirements fell from the peak demand months of July and August, when the daily peak values were around 1,500 MW in NP15 zone and approximately 2,000 MW in the SP15 zone to approximate daily peaks of 1,000 MW in NP15 zone and 1,200 in the SP15 zone during the months of October through December. The within-day pattern of the ISO's requirements for Regulation and the other ancillary services was far more stable across days from October through December than during the peak months of July, August and September.

One aspect of the operation of the ancillary services markets that suggests these markets are still not workably competitive can be seen be comparing the pattern of ancillary services requirements in the four markets for the months of October to December. The within-day pattern of the ISO's requirements for each ancillary service is very similar across the three months for both the NP15 and SP15 congestion zones. In fact, if the graphs were not labeled, it would be very difficult to tell the months apart. However, returning to Figures 2d-2f and Figures 2j-2l, the within-day patterns of prices across days in the months and across the three months are extremely different. Specifically, the prices in the four markets in December are dramatically different from the patterns in October and November, despite that fact the ISO's requirements for these markets are virtually identical across days within the each month and across the three months. This result suggests that much of the reason for the smoothness in the time path of prices in these markets during the months of October and November is not because these markets are any more workably competitive than they were during the summer months. This pattern of prices can be primarily explained by the low level of ISO loads during this period, which gave rise to ISO ancillary services requirements sufficiently low that there were limited opportunities for generators to set high prices in these markets.

e) *Bid Sufficiency in the ISO's Ancillary Services Markets*

Figure 4 plots the hourly bid sufficiency percentages for each ancillary service for each month from July to September.[3] Bid sufficiency is defined as the ratio of the total quantity bid (at any price) to divided the quantity required by the ISO. The total quantity bid into each market from each generation unit must account for the quantity that unit won in earlier A/S auctions. This is done by subtracting out the amount won in higher quality ancillary service auctions from the amount the unit bids into that ancillary services market. The August MSC discusses the process of computing bid insufficiency in detail. We present these graphs for NP15 and SP15. The value of bid sufficiency plotted in both the NP15 and SP15 figures is the value of bid sufficiency for the state-wide market when ancillary services are procured on a state-wide basis. During the periods, when ancillary services are procured on a zonal basis, the value of bid sufficiency plotted in the NP15 graph is for that congestion zone only and the value of bid sufficiency plotted in the SP15 graph is for that congestion zone. The periods when this occurred are denoted by the appearance of the "Congestion" variable plotted across the top of graph. Each graphs also contains a horizontal line at the value of 100% which is the minimum value of bid sufficiency for the market to provide the full level of the requirement for that ancillary service. On September 28, the ISO began purchasing upward and downward Regulation separately. Consequently, for Regulation we report the minimum of the bid sufficiency in the RegUp and RegDn markets as the value of the bid sufficiency for Regulation from this point onwards.

The graphs of bid sufficiency in July and August show many periods of bid insufficiency—values of bid sufficiency less than 100%. This was particularly true during periods of peak ISO load. One striking feature of these graphs is the tremendous *volatility* in bid sufficiency even throughout the day. Similar to the August MSC Report, we truncated the value of bid sufficiency, in this case at 900%. Any values of hourly bid sufficiency above 900% were plotted at this value. Many of the values plotted at 900% were significantly above this value. Figure 5a and 5b plot the monthly average frequency of hours when there is bid insufficiency in each ancillary services market. These graphs illustrate the general trends that can be seen from Figure 4a-4l. Average bid insufficiency frequencies declined from high levels in July, particularly for the NP15 congestion zone and Regulation and SP15 for Spinning Reserve. The highest level of average bid insufficiency occurred in the NP15 for Spinning Reserve and SP15 for Regulation. Both congestion zones showed intermediate levels of bid insufficiency for Replacement reserve and Non-Spinning reserve. The bid insufficiencies in all four markets dropped significantly in September and October relative to the levels in July. The pattern of bid insufficiencies in Regulation differed from those of the other three services. Bid insufficiencies in Regulation were lowest in August and September. This is due, in part, to the very high REPA payments to units providing that service during these months due to the high real-time prices of energy. For the other three ancillary services, bid insufficiency continues to occur, but less frequently than it did during the

[3] We understand that the data underlying Figure 4 may include bids in excess of the 25% limitation on imported contingency reserves, and therefore may overstate the true bid sufficiency for spinning and non-spinning reserves.

peak summer months. What is surprising from these graphs is that bid insufficiency occurred more often in November and December when all market participants could receive market-prices for ancillary services, relative to October, when the investor-owned utilities did not have market-pricing authority in these markets.

Figure 4a-4l indicate that periods of bid insufficiency in the four ancillary services markets tend to be coincident. When the hourly bid sufficiency graph for one market crosses below the 100% line it is usually accompanied by a bid sufficiency graph for another ancillary service. The within-day pattern of hourly bid sufficiency for the four ancillary services NP15 for October to December in Figures 4d-4f differ significantly across days and across months. In contrast, the within-day pattern of hourly ancillary services requirements for NP15 for October to December in Figures 3d-3f are considerably more regular across days and months. The periods of bid insufficiency in these markets are during the peak periods of the day. Each day the minimum bid sufficiency in each market and across all markets is extremely close to 100%, which is surprising given that these months are ISO load was extremely low relative to the months of July and August. Comparing Figures 4a-4c to Figures 4d-4f, the same pattern of minimum values of daily bid sufficiency occurs for these months of peak ISO load. In fact, for most days in these months the minimum daily bid sufficiency is further above 100% than it is in the months of October to December. This could be explained by comparing Figures 9a-9c to Figures 9d-9f. These figures show that the peak to valley in ISO load throughout the day is more pronounced during the peak months of the year than it is during October to December. There is more capacity up and running available to bid into the ancillary services markets during the low ISO load days of the peak months of July to September. The other difference between Figures 4a-4c and Figures 4d-4f is that when bid insufficiencies occur in October to December, they tend to occur just below 100%. However, in August to September, when bid insufficiency occurs, it tends to be at values further below 100%.

In the August MSC Report, we noted that bid insufficiencies in the ancillary services markets could be caused by the structure of the current RMR contracts. Since that time it has come to our attention that when a generator owning an RMR unit formerly owned by Southern California Edison received market-based pricing authority in the ancillary services market, it was also granted the authority to receive the market price for providing ancillary services under the terms of its RMR contract. Consequently, there are periods when it may be in the joint financial interest of these RMR unit owners to bid a small amount of capacity into the ancillary services markets at the $250/MW bid cap in order to cause a bid insufficiency in one of the ancillary services market. This in turn causes one or more of the units to be called under the terms of its RMR contract to provide ancillary services and receive this price $250/MW to provide this ancillary service. This incentive could explain why the daily minimum value of bid sufficiency is consistently close to the value of 100% regardless of the level of total ISO load.

f) Price Duration Curves

An alternative view of the volatility of prices in the ancillary services and real-time and PX energy markets can be obtained using “price duration curves.” These curves provide the following information on the variability of price over a given time period. Given a point on the vertical price axis, the value on the horizontal axis below the price duration curve below gives the percentage of observations with prices above this value. In a market with no price volatility, the price duration curves would be horizontal lines. In a market with a uniform distribution of prices, the price duration curves would be a downward sloping straight line.

We have chosen three periods over which to compare the variability of prices. The first period, from June 1 to August 5, corresponds to the period before out-of-state firms could participate in the ancillary services markets. The second period, from June 6 to November 2, corresponds to the period when out-of-state firms could participate in the ISO's ancillary services auction, but the IOUs did not have market-based pricing authority in the ancillary services markets. The final period, from November 3 to December 31, corresponds to the period when market participants had market-based pricing authority in the ISO's ancillary services markets. We compute price duration curves for each of these time periods for the four ancillary services markets, the real time energy market and the PX's day-ahead zonal market price for the NP15 and SP15 congestion zones.

A general pattern emerges from these three graphs. The frequency of high prices in all ancillary services markets declines across the three time periods. For a price above $25/MW on the vertical axis, each price duration curve is a leftward shift of the other. The price duration curves for ancillary services in the NP15 zone for the first time period, when only the new generation owners had market-based prices, are further to the left than those for SP15. Particularly for Regulation and Spin, the frequency of very high prices in the SP15 congestion zone is significantly higher than for the NP15 congestion zone. This is consistent with the logic discussed above concerning the incentives generators owning RMR units formerly owned by Southern California Edison have to set high prices and cause bid insufficiencies in the ancillary services markets. Perhaps the most pronounced change in Price Duration curves across the three time periods occurs for the Replacement reserve markets. The Price Duration curve for the third time period is very close to the horizontal line implied a period with no volatility in prices.

Comparing Figures 6e and 6f and 6k and 6l we can see that the remarkably similarity of price duration curves for the real-time prices and the zonal day-ahead prices for the same congestion zone. This is consistent with the point made in the August MSC Report that both generators and loads will attempt to arbitrage away any consistent price differences across the day-ahead and real-time energy markets.

g) Unit Level Bid Price and Bid Quantity Inequalities

As noted in the August MSC Report, the current procedures for the procuring ancillary services provide little incentives for the generators to submit bids for ancillary services that satisfy the quality inequalities discussed in the August MSC Report. Tables 2a and 2b investigate the frequency with which these bid price and quantity inequalities were violated during the three time periods for the investor owned-utilities (IOUs) and new generation owners (NGOs). These two categories of generation owners are defined in the

August MSC Report. For each generating unit level bid when assigned the bid price or quantity inequality a value of one if the bid price or quantity inequality noted in the first column its violated for than generator during that hour. For example, if the price bid inequality $P_{reg} \geq P_{spin} \geq P_{nspin} \geq P_{repl}$ does not hold for the bids from given generating unit and hour pair, this indicator is assigned value of 1. Each row of the table then gives the percentage of generating unit and hour pairs under each time period that this bid inequality was violated for each type of unit owner. For example, during the first time period from, June 1 to August 5, the frequency of violations of the bid price inequality $P_{reg} \geq P_{spin} \geq P_{nspin} \geq P_{repl}$ by investor-owned utilities is 0.74, meaning that approximately ¾ of the generating unit level prices for each hour do not satisfy this bid price inequality. Clearly, one explanation for this is the existence of REPA payment which adds the ex post real-time price to the amount paid for regulation. It is more difficult to explain the 0.37 value for the frequency of violations of the bid price inequality $P_{spin} \geq P_{nspin} \geq P_{repl}$ for IOUs. The NGOs have a slightly lower frequency of violations of this bid price inequality over the first time period. The frequency of violations of the bid price inequalities is consistent across the three bid price inequalities we investigated.

Violations of the bid quantity inequalities are empirically significant only for the first inequality $Q_{reg} \leq Q_{spin} \leq Q_{nspin} \leq Q_{repl}$, meaning that generators offer capacity to the Regulation market and then offer significantly less to the subsequent ancillary services markets. This result is consistent across the three time periods, with the exception of the third time period, when are generators have market-based pricing authority for ancillary services. During this period, the NGOs violate this generating unit-level quantity bid inequality less than 10 period of the time they submit bids to the four A/S markets. The only exception to the lack of violations of the subsequent bid quantity inequalities is the inequality $Q_{spin} \leq Q_{nspin} \leq Q_{repl}$, for the first time period.

h) PX and Real-Time Prices and Quantities

In order to assess the performance of the PX and real-time energy markets, in Figures 7a-7f and Figures 8a-8f we plot the hourly unconstrained day-ahead market-clearing PX and prices and quantities and the NP15 and SP15 real-time imbalance energy price and the total hourly imbalance energy sold in the real time market. Consistent with the observations made in the August MSC report, prices in the PX market tend to fluctuate hour-to-hour in a manner consistent with the cost of supplying electricity. Periods of high PX quantities tend to lead to higher PX prices. The volatility and mean of prices in the summer peak months of June to September is significantly higher than in the off-peak months of October to December. However, there are several puzzling price spikes in the PX that occur in the latter part of December, despite the fact that the market-clearing quantity of demand in the PX during these days is very similar to that in other days in October, November and December.

The real-time market shows a similar relationship between the quantity of net imbalances and real-time prices in both congestion zones. Prices in the real time market tend to be significantly more volatile than the unconstrained PX price. An interesting feature of the real-time price graphs is the very rare incidence of congestion in the real-time energy market during the peak summer months in Figures 8a-8c relative to the significantly greater incidence of congestion in the real-time energy market during the off-peak months in Figures 8d-8f. Based on the view that real-time congestion is more likely during high ISO load relative to low ISO load periods, this is an extremely counterintuitive result. What is even more interesting to note about these figures is the consistently higher real-time energy prices in the NP15 congestion zone versus the SP15 congestion zone during the months of October to December. Determining these the cause of these two results is a topic for further investigation by the MSC.

There has been considerable attention paid by market participants to what has been referred to as under-scheduling in the day-ahead and hour-energy markets. As noted in the August MSC Report and RMR Report prepared by Frank Wolak and James Bushnell, this under-scheduling is the natural consequence of the generators finding the highest-priced market to sell their output and load finding the lowest-priced market to purchase their output subject to the existence of a $250/MWh price cap in the real-time energy market versus at $2500/MWh price cap in the PX market. The RMR Report prepared by Wolak and Bushnell discusses this across-market arbitrage behavior in detail.

i) ISO Load Forecast and PX Market-Clearing Quantity

Figures 9a-9f plot the hourly PX market-clearing quantity and the day-ahead hourly ISO load forecast for each month from July to December. The difference between these two graphs each hour measures the extent to which the told amount of energy hedged in the PX day-ahead market is less than ISO load forecast for that same hour. There are several reasons that the ISO load forecast should be above PX day-ahead market-clearing quantity. The PX market-clearing quantity does not reflect the quantity of electricity traded each hour on bilateral contracts that will be generated in real-time. We would also expect that loads to account for the amount of RMR energy that will appear in the real-time market as a result of RMR energy calls scheduled on a day-ahead basis and in real-time. Finally, if a load that owns generation capacity knows it will schedule this generation in real-time, it need not hedge a quantity of demand equal to this generation in the PX market. The generator will receive the real-time price for all energy sold and the pay the same price for the real-time energy for an equivalent quantity of energy purchased from the real-time market, so it is completely hedged against variations in the real-time price of energy. Therefore, at least for the quantity of generation equal to its load obligations, this generator need not hedge in the day-ahead PX market, and thus need not submit demand or supply bids into the PX market. Consequently, there are many reasons for under-scheduling on a day-ahead basis unrelated to the exercise of market power by generators.

The PX market-clearing quantity is consistently below the ISO day-ahead load forecast for all hours from July to December. This difference is significantly higher in the peak hours of the day. The peak hour difference between the PX market-clearing quantity and the ISO load forecast is vastly higher in the peak months of July to September relative to the off-peak months. For example, during the first few days of September this difference is close to 15,000 MWh during the peak hours of these days. During the period October to December the peak hour difference rarely exceeds 5,000 MWh.

A final aspect worth noting about the operation of the ancillary services markets is the pattern of total bids submitted throughout the day by the two classes of market participants. Figures 10a-10f plot the aggregate quantity of total bids (regardless of the price at which it is bid) submitted by the IOUs for each month from June to December. Figures 10g-10l plots this same quantity for the NGOs. A consistent pattern of across all of the graphs for the IOUs is the large within-day variability in the total amount bid in each of the ancillary services markets. The other aspect of the graphs for the IOUs is the high frequency with which the total amount bid for a superior service exceeds that bid into the market for an inferior service. If IOUs were submitting their bids to satisfy the bid quantity inequalities discussed in the August MSC Report, the curves for these four services would never cross.

j) Hourly Bid Totals By IOUs and NGOs

Comparing the pattern of total hourly bids submitted by the NGOs reveals significantly less within day variability for all of the ancillary services besides replacement for the months of July to September. The amount submitted to the Replacement market is significantly more volatile, but significantly higher, in most hours of the day, than the amount submitted to the Non-spin market. This indicates that the NGOs want make sure to leave sufficient capacity available to supply replacement, should their bids in earlier markets be taken. During the months of October to December significantly less was bid into these markets by the NGOs. The lower envelope of Replacement bids in the period July to September now becomes the upper envelope of Replacement bids during these months. The amounts bids into all four markets show significantly less volatility than they did during the peak summer months. Why the NGOs are submitting significantly fewer bids to the ancillary services markets during these months is somewhat puzzling, given that bid insufficiencies continue to occur during this time period. Of course, this lower level of bid activity could be explained in part by scheduled maintenance plant outages. But the amount of capacity not being into these market is sufficiently large and for a sufficiently long period of time—more than two month—that outages are unlikely to be the only reason for this behavior.

B. August MSC Report Recommendations

The August MSC Report recommended to the ISO six specific measures that would, in the Committee's judgement, enable the ISO's ancillary services markets to become workably competitive. Those recommendations are described below.

1. Adoption of "Rational Buyer" Protocols

The ISO should implement "rational" purchasing practices for ancillary services that allow the ISO to substitute cheaper superior services for more expensive inferior services in its procurement of ancillary services.

2. Reform of Reliability Must-Run (RMR) Contracts

The ISO should revise RMR protocols and contracts so that these contracts no longer provide incentives for generating units with RMR contracts to bid and schedule less aggressively into the day-ahead energy market and ancillary services markets. This could involve creating a new class of true option contracts to replace most of the RMR contracts.

3. Approval for Market-Based Rates

The FERC should grant market-based rates for all market participants, assuming the ISO retains the authority to impose a damage control price cap.

4. Retention of a "Damage Control" Price-Cap

The FERC should allow the ISO to retain a damage control price-cap on all ancillary services that can be raised or lowered at the ISO's discretion, regardless of what decision is made on granting all firms market-based rates for all ancillary services.

5. Use of a Statewide Auction for Ancillary Reserves

The ISO should run the auction for ancillary services on a state-wide basis. If the state-wide market-clearing prices left a shortfall of supply in a given zone, the Committee recommended using RMR contracts to make up the shortfall.

6. Reduce the Demand for Regulation

The ISO should revise its scheduling and/or energy imbalance protocols to help reduce its need for regulation capacity.

7. Ambiguous Dispatch Practices for the Provision of Imbalance Energy

The ISO should establish transparent protocols for dispatching supplement energy bids and energy bids associated with ancillary services capacity in the real-time energy market.

C. ISO Market Redesign Proposals

On March 1, 1999, pursuant to the Commission's direction in its October 28th Order, the ISO filed the first major set of its ancillary services market redesign proposals.[4] These proposals included:

[4] On December 11, 1998, the ISO filed two other tariff changes relevant to ancillary services market redesign: the allocation of responsibility for ancillary services based on metered demand, rather than scheduled demand, and the withholding of payment for uninstructed deviations from ancillary service

1. Adoption of “Rational Buyer” Protocols

The ISO proposed to modify its ancillary service procurement process to enable the ISO to purchase additional quantities on one ancillary service that can substitute for another ancillary service, in order to reduce total ancillary services purchase costs.

2. Uninstructed Deviation and Replacement Reserve Allocation

The ISO proposed to adjust the amounts payable to the operators of resources that fail to comply with ISO dispatch instructions. The ISO also put forward a plan for it to purchase additional quantities of Replacement reserves to cover any forecast deficiencies in available energy, in order to reduce the ISO's reliance on out-of-market purchases for that purpose. The cost of this additional Replacement reserves is allocated to loads in proportion to the extent that their hour-ahead energy schedules are below their real-time consumption, and to generation in proportion to the extent their real-time generation falls short of their hour-ahead energy schedule. In this sense loads, are punished for scheduling less than their demands in the real-time market, and generators are punished for underproducing energy relative to hour-ahead schedules.

A major way demand protects itself from the attempts of generators to set high prices in the PX and ISO energy markets during peak ISO load periods, is by shifting loads between these markets and routinely scheduling significantly less energy on an hour-ahead basis than its expects to consume in the real time market. Consequently, this scheme will increase the cost of such defensive actions by demand, thereby making higher PX and ISO energy prices more likely.

3. Automation of Dispatch Instructions for Real-Time Energy

The ISO described how it would automate the communication of dispatch instructions to resources supplying imbalance energy in order to allow the ISO to make better use of those resources, thereby reducing its requirements for regulation service. (No changes to the ISO's tariff or protocols were required for this element of the redesign package.)

4. Separate Pricing of Regulation Up and Regulation Down

The ISO proposed to introduce separate pricing for the upward and downward components of regulation service in attempt to increase the efficiency of the regulation market.

The MSC recommends that the ISO explore other options besides the separate procurement of upward and downward regulation for improving the efficiency of this market and reducing the demand for regulation. As noted above in our analysis of the market operation since August, the continued periodic bid insufficiencies and price spikes

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capacity. These changes have not yet taken effect, but are expected to be implemented in the Spring of 1999 in the regulation market suggest that it is a thin market that is not workably competitive. Further segmenting an already thin market may only serve to enhance the opportunities generators have to set high prices in these two markets, with no gains in overall market efficiency.

5. Reduced Transaction Costs for Loads Participating in A/S Markets

The ISO proposed to develop an agreement to facilitate the participation of dispatchable loads in ancillary service markets. The Participating Load Agreement (PLA) is the load counterpart of the Participating Generator Agreement (PGA). It is a pro forma contract to standardize load participation in the non-spin and replacement markets. (No changes to the ISO Tariff or Protocols or to ISO software were required for this element of the redesign package.)

As stated in the August MSC Report, any efforts to increase the ability of demand to participate in the PX and ISO markets and to respond to high prices can only enhance the efficiency of these markets. The MSC continues to believe recommendations to allow the signing of forward contracts for ancillary services and incentives to increase the spread real-time metering of loads will benefit to all market participants in terms of lower ancillary services price volatility and lower ancillary services prices.

6. Trading of Ancillary Services

The ISO proposed certain modifications to permit Scheduling Coordinators (SCs) to engage in trades of ancillary services, with the intention of providing alternative means for SCs to fulfill their ancillary-service obligations.[5]

D. Status of August MSC Report Recommendations

The Commission and the ISO have carried out, or are in the process of implementing in whole or part, most of the Committee's recommendations, as more fully described below.

1. "Rational Buyer" Protocols

The first phase of the ISO's market redesign proposal (filed March 1, 1999) implements several features of the MSC's rational buyer recommendation. We believe that the changes proposed by the ISO represent a significant and positive step towards improving the performance of the ISO's ancillary services markets. Fundamentally, improved flexibility in the ISO's procurement practices will tend to undermine any market power

[5] The March 1 filing also included: (1) proposed modifications to the Ancillary Services Requirements Protocol ("ASRP") to reflect the ISO's new requirements concerning communications and direct control systems for units providing Regulation service; (2) a proposed modification to the ISO Tariff to provide for the payment of amounts due for Ancillary Service capacity dispatched under certain RMR contracts to the relevant Participating Transmission Owner; and (3) a change to the Market Monitoring Information Protocol to clarify the relationship between the ISO and the independent Market Surveillance Committee

that suppliers of ancillary services might otherwise enjoy. However, there are several important features of the MSC's recommendations that were not adopted. We would also like to offer some suggestions for improving the effectiveness of the ISO's Rational Buyer Protocol.

We begin by describing the Rational Buyer protocol adopted by the ISO Board to determine how the ISO will purchase its ancillary services requirements, and how prices for the four ancillary services will be set. We call this the "ISO's Rational Buyer Protocol." The starting point for this protocol is the ISO's initial ancillary services requirements, based on the WSCC standards. The ISO's Rational Buyer Protocol allows the ISO to shift its demands for the four ancillary services in the following manner in response to the bid curves submitted for each of the ancillary services: the ISO can reduce the demand for a lower-quality ancillary service so as to reduce the total cost to the ISO of purchasing ancillary services.[6] For example, if the bids are such that it is cheaper for the ISO to purchase more regulation and less spin, then the ISO's Rational Buyer Protocol allows this to happen. Given bid curves for each of the ancillary services, the ISO's Rational Buyer Protocol permits the ISO to find the least-cost method to satisfy its initial reserve requirements.[7]

Operationally, the ISO's Rational Buyer Protocol requires that the ISO determine the mix of reserve requirements that meets its total reserve capacity needs and results in the lowest total costs of ancillary services. These are the ISO's Rational Buyer Quantities. Once the ISO's Rational Buyer Quantities for each of the four services have been determined, the ISO's original sequential bid software can then be run to determine the resulting ISO's Rational Buyer *Prices*. For each service, the ISO's Rational Buyer Price is simply the price necessary to call forth the ISO's Rational Buyer Quantity of that service, according to the aggregate bids offered for that service.[8] It is important to emphasize that the ISO's Rational Buyer Protocol makes no changes to the bid curves submitted to the ISO; it only adjusts the *quantity* of each ancillary service procured by the ISO. This version of Rational Buyer protocol has therefore been referred to as the *demand-substituting* rational buyer.[9]

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[6] The quality hierarchy of the ancillary services is, from highest to lowest quality: regulation, spin, non-spin and replacement.

[7] This may involve the ISO purchasing a greater quantity of a higher-quality service than was needed, and correspondingly less of a lower-quality service.

[8] The aggregate bid curve for each service is constructed by taking the total amount bid for that service for each unit less the quantities won from that unit in previous higher-quality ancillary services auctions and ordering these bids from lowest price to highest price. The sequential nature of the ISO's ancillary services auctions is discussed in greater detail in the August MSC Report.

[9] Several market participants have argued that the ISO's Rational Buyer Protocol implies that the ISO is exercising monopsony power as a single buyer. However, it is important to recall that in order to exercise monopsony power, a buyer must be able to restrict the amount it purchases. In this case, the ISO's Rational Buyer Protocol involves the ISO purchasing the same total quantity of ancillary services capacity. The only difference between the Rational Buyer quantities and the ISO's original ancillary services quantities is the *composition* of ancillary services purchases. The protocol thus allows the ISO to protect itself against the exercise of market power, but not to exercise monopsony power in meeting all of its ancillary services needs.

The ISO's Rational Buyer Protocol employs different settlement procedures than were procedures recommended by the MSC in our August 1998 report. Under the ISO's proposed protocol, although the ISO indeed purchases the Rational Buyer Quantities of each ancillary service, those ultimately paying for ancillary services, and those providing their own ancillary services, must only pay for or self-provide a quantity for each service equal to the ISO's *initial* ancillary services requirements (i.e., prior to any rational-buyer adjustments). For example, if the ISO's initial requirement for regulation reserve is 3% of the ISO's load, but the ISO's Rational Buyer Protocol results in purchasing regulation reserve amounting to 5% of the ISO's load, then both demanders and self-providers must purchase or provide regulation amounting to 3% of their load. This settlement procedure tends to create a subsidy to self-providers of ancillary services, because the total amount the ISO pays to providers of ancillary services under this scheme will generally be less than the total amount collected from purchasers of ancillary services. As a result, self-providers of ancillary services will have diminished incentives to make adjustments that would cause the rational-buyer prices to satisfy the inequalities that higher-quality ancillary services sell for higher prices, which was one of the major goals of adopting a rational buyer protocol to begin with.

The Committee recognizes that both equity and efficiency concerns are implicated in the settlements procedure that is adopted in conjunction with the ISO's Rational Buyer Protocol. We would prefer to see a settlement method that does not introduce subsidies into the system, and that conveys more accurate price signals to users and self-providers of ancillary services. As a general rule, the Committee is disinclined to give great weight to equity arguments based on so-called entitlements resulting from flaws in the market design that the ISO is in the process of fixing, especially if such equity considerations impede the efficient operations of the ISO's markets.

Although we are unable to measure the magnitude of market inefficiencies associated with the ISO's proposed settlement scheme, we would counsel against introducing further complexity and inefficiency absent a compelling reason to do so. We expect, however, that the ISO's procedures will result in lower costs for regulation reserve than would occur if purchasers and self-providers of ancillary services faced obligations equal to the ISO's total purchases of each ancillary service. We therefore expect that fewer generators will be willing to make the investments in the automatic generation control (AGC) technology necessary to provide regulation reserve service. Given the high levels of regulation required by the ISO for successful operation of the California market design, there should be strong incentives for generators to install the AGC technology necessary to provide regulation.

We do not believe it would be difficult to modify the ISO's protocol to eliminate the subsidies to self-providers of ancillary services. All that is required is to make all consumers of ancillary services purchase them in the same quantities that the ISO actually procures them, i.e., the ISO's Rational Buyer Quantities. Returning to our previous example, if the ISO's Rational Buyer purchased regulation at 5% of ISO load, then all demand would be obligated to purchase regulation in the amount of 5% of their load. Both self-providers and those who purchased regulation from the ISO would face the same 5% of load obligation. The same principle would apply to the other three ancillary services: both self-providers and purchasers of ancillary services would be obligated to purchase the ISO's Rational Buyer Quantities.

Our proposal would enhance market efficiency in two important respects. First, the ISO would not be taking a net position in ancillary services, as it would under the ISO's Rational Buyer Protocol. Under our proposed protocol, the total cost of ancillary services would exactly equal the total revenue collected by the ISO from purchasers of ancillary services. Second, the self-providers would have very strong incentives to sell their capacity or self-provide in such a manner that the price of a higher-quality ancillary service is at least as large as the price of a lower-quality ancillary service. Ultimately, then, our procedures would provide the strong incentives for all participants—self providers and purchasers of ancillary services—to cause the ISO's original ancillary-services demands to be no different from its Rational Buyer Quantities. Consequently, this proposal would ultimately raise little or no equity concerns, and would have an attractive simplicity to it.

In summary, although the current ISO Rational Buyer Protocol is a positive step towards more workably competitive ancillary-services markets, the Committee hopes that the ISO will take the very important additional step to eliminate the subsidies to self-providers of ancillary services inherent in its current proposal. We do not believe that it would be very difficult to implement an efficient protocol lacking these cross-subsidies.

2. RMR Contracts

The Committee, and particularly its Chairman, Frank Wolak, have given significant attention to RMR issues since the August MSC Report. Our findings and recommendations appear in Section V, below. We understand that the ISO, FERC staff, and market participants are likely to file an offer of settlement with the Commission shortly that will deal with some but not all of the issues identified by the Committee. The Committee's views on the settlement proposal are continued below in Section V.

3. Market-Based Rates.

The Commission has eliminated cost-based rates for ancillary services provided by all market participants, and authorized market-based rates for those services. This step is a prerequisite to workably competitive ancillary services markets. However, as the Committee noted in its August report, the ownership and control of the PG&E hydro units requires particular attention. Since August, PG&E has proposed selling all of its hydro facilities to an affiliate at an appraised price. Careful analysis of this proposal is necessary in order to determine whether selling all of the units to a single affiliated buyer will permit PG&E (or its affiliate) to exercise market power in California's energy and ancillary services markets.

In the previous vertically integrated, price-regulated utility regime, hydroelectric facilities were used to make more efficient use of the utility's fossil fuel plant. If demand was expected to be extremely high during a specific hour, a utility attempting to minimize total dispatch costs over some time horizon would use its hydroelectric plant to reduce the use of extremely high-cost fossil units in high demand periods.

In a competitive electricity market, quick-response hydroelectric units with low marginal costs are extremely valuable to a generator with any market power. In the new competitive regime, a hydroelectric plant owner may not find it profit-maximizing to sell a sufficient amount of hydroelectric output to limit the amount of energy called from high-cost fossil units during peak-demand periods. A profit-maximizing generator may instead prefer not to reduce these high prices by selling more output during these periods and instead sell any of its unused hydroelectric output during off-peak periods. By following this strategy, the hydroelectric plant owner will earn higher prices for all the generating capacity it owns. Using its hydroelectric plants to *increase* the magnitude of price spikes in the energy and ancillary services markets, a generator owning a portfolio of hydroelectric and fossil plants can in theory earn a higher level of profits than it would using this plant to shave the price peaks as it did in the former vertically-integrated, price-regulated regime.[10] For this reason, hydroelectric capacity is particularly valuable to generator that owns a portfolio of generating plant and potentially disruptive to the efficient operation of a competitive electricity market.

4. Damage Control Price-Cap

The Commission has permitted the ISO to retain authority to impose a market-wide "damage control" cap on ancillary service bids. The cap is currently set at $250/MW. A $250/MWH cap on real-time energy bids is also in place, pursuant to the Commission's order of January 27, 1999. As discussed more fully below, the Committee recommends that the ISO retain the authority to set and change these caps, and that caps be raised to the $2500 level, in two phases, as soon as market conditions permit.

5. State-wide Auction for Ancillary Services

In its August report, the Committee recommended a state-wide auction for ancillary services, using RMR contracts to make up any shortfall in a particular zone. The ISO has not fully adopted this proposal because it believes the proposal to be inconsistent with its policy to use RMR contracts only to ensure grid reliability. The Committee continues to believe that this recommendation is sound policy. However, we do not regard implementing this particular proposal as a necessary prerequisite to raising the price caps. Nonetheless, we believe that some timetable should be put in place for integrating the ISO's congestion management protocols for the day-ahead, hour-ahead and real-time energy markets with its procedures for procuring ancillary services. It is our understanding that some steps have been taken in this direction. The ISO has

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[10] For an analysis of the use of hydroelectric assets in a competitive electricity market, see James Bushnell, "Water and Power: Hydroelectric Resources in the Era of Competition in the Western U.S.," POWER Working Paper PWP-056, University of California Energy Institute, July 1998.

significantly reduced the number of periods when ancillary services are procured on zonal basis.

6. ISO Procurement Practices

Two major issues that remain unresolved from the August MSC report are the ISO's procedures for procuring regulation reserve and the transparency of the ISO's process for dispatching reserve capacity from the real-time energy bid stack. The ISO has implemented several market design changes to address both of these issues. However, it appears that the philosophy underlying the California market design, which does not require generators to follow their net day-ahead and hour-ahead energy schedules in real time, makes it difficult fully to solve these problems. This additional freedom given to generators creates greater uncertainty for the ISO about how it will meet real-time demand with generation, relative to a system where energy schedules are firm physical commitments to supply energy and generators face strong financial penalties for deviations from these energy schedules. The ISO manages this increased uncertainty by purchasing more regulation capacity than was used in the pre-ISO regime. This increased regulation capacity allows the ISO to respond instantaneously to any local energy needs due to deviations by non-regulating generators from their net day-ahead and hour-ahead energy schedules.

The ISO continues to purchase regulation reserve significantly above the levels that occurred during the regulated regime. Because the California market design does not impose any explicit penalties on generators or loads for any real-time uninstructed deviations from the aggregate of their hour-ahead energy schedules, generators will deviate from these schedules when it is in their financial interest to do so. Any hourly net imbalance between a generator's or load's scheduled production or consumption must be paid for or charged at the hourly real-time energy price. This hourly real-time price is computed as follows. Every 10-minutes the ISO runs the Balancing Energy and Ex Post Pricing (BEEP) and a 10-minute price is determined. This produces incremental and decremental instructions for generators who have bid into the real-time energy market or reserve capacity that has won in day-head and hour-ahead ancillary services markets (except regulation). In any given 10-minute interval there can be both a zonal incremental price and a zonal decremental price. The *ex post* real-time price for a given hour is therefore the quantity weighted average of the six decremental prices and the six incremental prices for that hour. The quantity for the decremental price is the sum of the absolute values of the decremental instructed deviations for that 10-minute interval, and the quantity for incremental price is the sum of the incremental instructed deviations for that 10-minute interval. The hourly real-time price is then obtained by taking the sum of these twelve price/quantity pairs for given hour and dividing by the sum of these 12 quantities for that hour.

Deviations from a generating unit's schedule as a result of an instruction by the ISO to increase or reduce its supply to the real-time energy stack are billed at the 10-minute price associated with these instructed deviations. However, the ISO's settlements system is only able to compute the total amount of energy generated in a given hour.

Consequently, the ISO has no way of knowing whether the instructed deviation associated with a given 10-minute price has been followed. The ISO's settlements process assumes that generators follow all 10-minute instructed deviations, and that these are paid for at the relevant 10-minute price. Any remaining deviation from the net day-ahead and hour-ahead energy schedules, and sum of the six 10-minute instructed incremental or decremental deviations for that hour, is cleared at the hourly real-time price. This real-time price-setting process, in combination with the freedom to deviate from energy schedules, tends to increase the demand for regulation.

Unfortunately, this system has created some undesirable gaming opportunities for generators. Because the price for a given 10-minute interval is posted on the Public Market Information (PMI) site as soon as it is known , a generator operating during the last 10 minutes of an hour is able to formulate an estimate of the real time ex post price for this hour. Consequently, if this real-time price is expected to be sufficiently high relative to the generator's marginal cost, the generator will have an strong incentive to over-produce during the last ten minutes of the hour. This will cause the BEEP to produce a significantly lower price for the first ten minutes of the following hour as a result of decrementing several units operating during the last ten minutes of the previous hour. This creates a further increase in the demand for regulation to manage the surges of generation at the end of some hours and the rapid declines in during the first ten minutes of the following hour.

We also note that the ambiguous dispatch of generating units providing reserve capacity in the real-time BEEP stack noted in the August MSC report continues to occur. This problem can be traced in part to the philosophy underlying the California market design. Many generators do not submit bids into any of the three ancillary services capacity markets yet do bid supplemental energy into the real-time energy stack. One reason for this behavior is that a winning capacity bid placed in the real-time energy stack cannot be removed without a substantial penalty to the generator. However, a bid into the real-time energy stack during a given hour of the day is not considered firm until 45 minutes before the hour in which the energy will be supplied (and until 20 minutes before the hour for out-of-control-area bids). Consequently, bids into the real-time market can and are often removed a short time before the hour in question, especially during periods when the ISO forecasts high loads. The generator would prefer to be paid a higher price or receive more attractive terms (for instance, a longer production time commitment) under an outside-of-market transaction rather than remain in the BEEP stack. This ability to withdraw capacity on short notice from the BEEP stack, in combination with the inability to verify if 10-minute BEEP instructions to generators are followed, often leaves the ISO with no option but to skip over energy bids in the BEEP stack from capacity that has won in the spin or non-spin ancillary services markets, in order maintain a sufficient amount of quick response reserve capacity.

Several remedies have been suggested to reduce the ISO's demand for regulation. A fundamental source of the current over-procurement of regulation is the fact that generators find it profitable to arbitrage differences between the hourly real-time price and the 10-minute price for instructed deviations, particularly during the first and last 10-

minute intervals of an hour. One solution is to settle with generators at 10-minute prices and quantities. This would considerably increase the complexity of the settlement process by multiplying the number of time periods during the day by a factor of six. The ISO's current proposal to have each generator pay for uninstructed deviations at that generator's "effective price," the instructed quantity weighted sum of its BEEP interval prices during the duration of the dispatch instruction, does not provide any financial incentive for the generator to comply (or not comply) with these instructed deviations. Another remedy proposed by the ISO is to increase the ISO's demand for replacement reserve to insure a deeper and more reliable BEEP stack.

This remedy is part of the ISO's current proposal to purchase increased amounts of replacement reserve in periods when the ISO believes that there is significant under-scheduling of generation and loads on a day-ahead basis. This increased replacement capacity will then be charged to both loads and generation in proportion to the amount that they under-schedule in the day-ahead and hour-ahead markets. It is worth noting that this proposal will increase the costs to loads and generators from shifting their demands and supplies between the day-ahead, hour-ahead and real-time markets. This scheme therefore increases the cost to loads of bidding a price response into the PX and therefore substituting into the hour-ahead and real-time markets if generators bid too high in the PX. The result of this implicit tax on load shifting may increased prices in both the PX and real-time energy market.

Another remedy is to require that bids into the real-time energy market be submitted further in advance of the actual hour they may be asked to provide energy, and to impose penalties on generators who remove these bids in advance of the market (similar to those that are imposed on energy bids from winning ancillary services capacity). This remedy would allow the ISO to reduce its purchases of all ancillary services because the BEEP stack could then be treated in much the same way as reserve capacity coming through one of the ancillary services markets. Making real-time energy bids a genuine commitment for an extended period of time would also allow the ISO to end its current practice of skipping over energy bids of units providing spin and non-spin reserve capacity.

Because the current market design often creates incentives for generators not to follow the sum of day-ahead and hour-ahead energy schedules or 10-minute instructed deviations, to some extent increased procurement of regulation may simply be one of the inevitable costs associated with the current market design. Because price signals are the only available tool to discipline deviations by generators, these signals must be particularly strong and accurate. It is impossible to use an hourly price to discipline deviations *within* the hour that are financially beneficial to the generator. Ideally, we would like prices and quantities to clear second-by-second and generators to pay for imbalances relative schedules at this second-by-second price. Clearly, such a settlement scheme is beyond the range of technological feasibility. Consequently, over-procurement of regulation may be a necessary to correct this mismatch between the time intervals over which instructed deviations are paid versus uninstructed deviations.

7. Summary

In sum, the Committee's recommendations to move to market-based rates have been substantially carried out., or will be if the ISO's March 1st filing is approved.

The ISO's Rational Buyer Protocol, as currently implemented, is a significant step towards workably-competitive ancillary-services markets. However, the settlement procedures proposed by the ISO do create certain incentives that tend to partially undo its desirable properties for inducing market-clearing prices in which higher quality ancillary services trade for more than lower-quality services. The ISO's Rational Buyer Protocol should therefore be modified in line with recommendations given above by the Committee.

The Committee's RMR and state-wide auction recommendations have not been fully implemented; see below for details.

By increasing the requirements that bidders in the real-time energy market provide advance notice, and by imposing a penalty for bid withdrawal, the demand for all ancillary services can be reduced.

As discussed more fully below, if the ISO's Rational Buyer Protocol in its March 1st filing is implemented, along with the modifications suggested above, and if full reform of the RMR contracts is implemented, it is our judgement that the ISO's ancillary services and real-time energy markets will become workably competitive, so that the $250 caps can be raised two phases to $2500. However, until these ancillary services market changes are approved, and the RMR contract redesign is completed, we do not recommend raising the $250 caps above their present levels.

The Committee also encourages the ISO to develop performance measures; the Committee intends to work with the ISO to this end. Such measures should provide the ISO with increased incentives to reduce its purchases of ancillary services. As we noted in our August 1998 report, the ISO has an extremely strong incentive to maintain system reliability, but the ISO may not have as strong an incentive to achieve reliability at least cost.[11]

[11] This problem is hardly unique to the California market. For example, during the early years of the market in England and Wales, ancillary services purchases by the National Grid Company (NGC) showed a steady increase, going from £112.1 million in the 1990/91 fiscal year to £157.7 million in the 1993/94 fiscal year. As a result of this trend, in 1994 the Office of Electricity Regulation (Offer) instituted the Transmission Services Scheme. This arrangement allows NGC to keep cost savings or pay costs incurred beyond a target cost amount, thus encouraging it to minimize "avoidable costs" in managing the transmission grid. Since that time the costs of ancillary services have fallen, despite the fact that annual total system load has continued to grow. For the 1997/98 fiscal year, the total cost of ancillary services was back down to £117.5 million.

E. Longer-Term Redesign of Ancillary-Services Markets

The ISO continues to work with stakeholders to improve to design of its ancillary-services and real-time markets. Through this process, a number of longer-term redesign projects, referred to as “Ancillary Services Redesign Elements,” have been identified. For the purpose of completeness, we report here our understanding of these elements. The Committee intends to continue to monitor progress on these redesign elements.

1. Integration of Ancillary Services and Congestion Management

This project involves integration of ancillary service and congestion management functions. Hopefully, the implementation of this design element will enhance the market-based approach to reliable operation. For example, this design element may allow the ISO to lift the existing 25% cap on the amount of Contingency Reserves (Spin and Non-spin) that is imported, by providing an arbitrage opportunity between the use of transmission capacity to import energy or ancillary services.

2. Import of Regulation

This element involves implementation of communication and control systems (“Dynamic Scheduling and Control”) to permit the ISO to import regulation, thus making the market for regulation more competitive.

3. Use of Non-Firm Export for Non-Spin and Replacement Reserves

This element involves implementation of communication and confirmation mechanisms to link an internal generator to the interruptible export on a tie. Interruptible exports can increase the supply of non-spin and replacement reserves.

4. Load Following/Ramping

To perform the load-following function, the ISO has been using excessive regulation capacity, in comparison with the operating practices of integrated utilities. This redesign element involves implementation of a load following/ramping function to reduce the current excessive burden on regulation reserve.

5. Split BEEP Stack

This element involves splitting the BEEP stack into two new energy bid stacks. One stack would exclusively include the energy bids for contingency reserves (spin and non-spin); the other would hold the replacement reserve and supplemental energy bids. This element is intended to address the concerns stated in our August report (as well as by some stakeholders) that control room operators skip over some contingency reserve bids during peak periods. This design element is meant to improve operational transparency.

Given the thinness of the current BEEP stack and the volatility of prices in the real-time energy market, particularly in the peak ISO load periods, it may not be advisable to further subdivide this market. It may simply enhance the opportunities generators have to set high prices in the real-time energy market.

6. Ability to Bid and Self-Provide an Ancillary Service From a One Unit

Currently, scheduling coordinators can bid and self-provide ancillary services from the same unit, but the bid and self-provision must be of *different* ancillary services. New software would remove that limitation.

7. Multiple Ramp Rates

This feature will allow the scheduling coordinators to specify different ramp rates for different loading levels on a unit, thus improving their ability to comply with ISO's dispatch instructions. The result should be a more reliable BEEP stack.

8. Preserve Firmness of Imports

This redesign element involves implementation of new software to preserve the firmness of imports in inter-SC trades and allow credit for firm imports when ancillary services are procured zonally. Hopefully, this element will increase the competitiveness of ancillary services imports, particularly in conjunction with the implementation of the Firm Transmission Rights program.

IV. REAL-TIME ENERGY MARKETS

A. Background

The real-time (or imbalance) energy market price is the only energy price set through ISO market processes. This price is used to settle deviations from scheduled supply and demand: those providing extra supply (or reduced demand) will earn this price and those providing extra demand (or under supply) will pay it. Recall from the above discussion that only instructed deviations resulting from the BEEP process change the 10-minute real-time incremental and decremental prices, and the quantity (incremental and decremental) weighted average of these prices for the hour is the real-time price. Because real-time prices are determined based on instructed deviations only, the extent to which total ISO load is not hedged in the PX day-ahead and hour-ahead markets does not directly impact the real-time price for that hour. Only if additional generation must be called upon from the BEEP stack will the real-time price be affected. For example, if a participant knows that a certain amount of its generation will produce in real-time and this exactly equals the amount of load obligations it has not hedged in the PX markets, the generator's transactions in the real-time market exactly balance. It sells this generation for the hourly real time price and buys it at this same real-time price. Consequently, its profit margin on the amount of electricity it produces is the difference between the net retail revenues in receives for this energy and the cost of producing this energy, so it is completely hedged against movements in the real-time price of electricity for this load.

The ISO acquires real-time imbalance energy from any one of five sources: from the four hourly ancillary services markets, and from suppliers who bid to provide “increments” and “decrements” to their day-ahead energy schedules. Suppliers who have committed capacity to one of the ancillary service markets, and who also produce energy, receive the imbalance energy price in addition to their respective ancillary-service capacity payment. Suppliers who provide energy through supplemental energy bids receive the imbalance energy price only for uninstructed deviations during a given hour.

Each provider of ancillary services submits bids to supply energy from its ancillary service capacity. Other generators may submit energy bids for the imbalance market through supplemental energy bids. The ISO combines these energy bids into a system-wide bid-curve for incremental energy, known as the “BEEP stack”. If additional energy is needed in real-time, the ISO will dispatch, subject to technical operating constraints on the units, the unit with lowest energy bid that is currently available, thereby moving “up” the bid stack. Generation and demand that has already been scheduled can also submit “decremental” adjustment bids to be used in the event that supply exceeds demand in real-time.

B. Relationships Between Real-Time Energy Other Energy Markets

As noted above, the forward (day-ahead, hour-ahead) energy markets, the real-time energy market, and the ancillary-services markets are largely served by the same generating units. Because of limitations on the capability of the ISO’s software, the ISO maintained until January 1999, a $250 MWH price cap (known as the “BEEP cap”) on real-time energy prices. When the software was modified in January 1999, the FERC required this cap to be eliminated, but permitted the ISO to impose a “damage control” cap in the real-time energy market comparable to that in effect for ancillary services. The ISO has set the real-time energy damage-control cap at $250/MWH. This cap has important price effects on the PX day-ahead and hour-ahead markets, which are nominally capped at $2500/MWH. Purchasers, knowing that real-time energy will not rise above $250/MWH are unwilling to bid more than $250 for forward energy, preferring instead to purchase imbalances at a maximum of $250 in the real-time market.

The Committee, in an opinion rendered to the ISO on November 12, 1998,[12] recommended that any change in the price cap for real-time energy be carefully coordinated with ancillary-services price caps, and with the restructuring of the RMR contracts. We stated at that time:

[12] Opinion of California Independent System Operator Market Surveillance Committee respecting Phased Increase in BEEP and Ancillary Services Caps, November 12, 1998. This opinion is appended as Attachment B. The Committee also noted that an alternative means of coordinating the two caps would be to remove the ancillary services cap rather than temporarily retaining the BEEP cap. The Committee thought, however, that this action must await implementation of several key market reforms, including implementation of the rational buyer protocol and reform of the current RMR contracts.

> [T]he cap on the real-time energy price serves as an effective constraint on the level of bids in the PX day-ahead market. The ISO would be ill-advised to remove the BEEP cap without assurance that market power cannot be exercised in the PX day-ahead market and that incentives for withholding under the current RMR contracts have been remedied.

This is a concern because the day-ahead energy, real-time energy, and the four ancillary services markets are largely served by the same generation units. Removal of the cap in the real-time energy market may make that market more profitable than the ancillary services markets still subject to price caps, potentially drying up bids into the latter markets, particularly in situations where bidding behavior may be distorted by RMR contract incentives to withhold capacity.

C. November MSC Recommendations

The MSC's November 1998 opinion laid out a series of recommendations with respect to coordinated action to redesign the ISO's ancillary services and energy markets and then to raise all of the ISO price caps to $2500 in two phases. These recommendations have been incorporated into Section VI of this report.

V. RELIABILITY MUST-RUN CONTRACTS

A. The Current RMR Contracts and Their Effects

The RMR contracts give the ISO the right to call certain in-state generating units to provide energy or ancillary services at cost-based rates in order to ensure reliable operation of the grid. Three types of RMR contracts[13] are currently in effect: The "A Contract," the "B Contract" and the "C Contract." The contracts are described below.

A Contract: This contract provides for no up-front payment to recover fixed costs. Rather it provides for recovery of those costs through a fixed $/MWh "reliability payment" to be made whenever the unit is called under the contract. The "A Contract" also allows recovery of variable and start-up costs when the unit called. This payment rate folds in the recovery of fixed costs. The generator may elect to bid into the PX auction markets, in which case it receives the market price instead of the reliability payment rate.

B Contract: Under this contract, the generator receives a specified up-front payment to cover a portion of the unit's fixed costs for a maximum number of hours during which it can be called under the contract, and a payment to cover variable costs and start-up costs when the unit is actually called under the contract. The generator may participate in the PX and ISO markets under this contract, but is required to credit back to the ISO 90% of market net (of variable cost) revenues.

C Contract: Under this contract, the unit receives an up-front payment to cover all of its fixed costs, plus variable and start-up cost payments when called. Units under the "C Contract may not participate in the PX or ISO markets.

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13 Technically, the RMR "contracts" are rate schedules unilaterally filed by the generators that have been accepted for filing under the Federal Power Act, rather than contracts. The ISO has not executed the documents and is contesting their terms and conditions in proceedings before FERC.

The August MSC Report (pages 35-39) expressed concerns that the RMR contracts created perverse incentives for generators to bid less aggressively into the ancillary services markets. The August MSC Report also noted that for similar reasons the current RMR contract would impact bidding in the PX day-ahead market. Frank Wolak and James Bushnell prepared a detailed econometric analysis of PX bid data and ISO data to assess the impact of the RMR contracts on generator bidding behavior in the PX market (The Wolak and Bushnell Study).[14] A preliminary version of this analysis was made available to the ISO and to participants in the RMR settlement negotiations on December 7, 1998. The view of Wolak and Bushnell was that the reliability variable payment rate under the "A Contract" and the credit-back provisions of the "B Contract" had significant effects on the price and quantity of energy bid into the PX.

Wolak and Bushnell pointed out two ways that the current RMR contracts impact bidding in PX market.[15] First, the RMR Contract is an insurance policy against bidding too high and not winning in PX, for capacity covered the RMR contract. We call this the "insurance" effect of RMR contracts on bidding behavior. The "A Contract" provides a greater degree of such insurance against losing in the PX day-ahead market than the "B Contract," because the payment rate under the "A Contract" contains a component for fixed cost recovery per unit of output provided, but this insurance against not selling into the PX market is still present for the "B Contract." The second effect arises because higher-priced bids by owners of RMR capacity may result in a higher PX price which is earned by all units a firm owns. We call this the "portfolio effect" of RMR contracts on bidding behavior. This portfolio effect is present for both types of RMR contracts. It is particularly acute for the "B Contract," for which a generator must refund 90% of its market net revenues.

To illustrate the insurance effect, suppose a unit has an RMR Contract payment rate of \$100/MWH. If this unit fails to win in the PX and is called under its RMR contract for a given number of hours, it earns \$100/MWH. Suppose that the company owning this unit assesses the probability the unit will be called under its RMR contract at 0.4. Its expected revenue from staying out of the market is 0.4 x \$100 or \$40/MWH. The forgone revenue from not being called under the RMR contract is \$40/MWH. Assuming the same expected quantity sold under its RMR contract as it hedges through day-ahead market at the PX price implies that the generator would not hedge this generation in the day-ahead market at a price below this opportunity cost of \$40/MWH.

The portfolio effect is especially strong under the "B Contract" because a generator that gives up a very small amount of variable profits from such an RMR unit (after accounting

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[14] "Reliability Must-Run Contracts for the California Electricity Market," Frank A. Wolak and James Bushnell, Attachment C, which will be produced shortly, as soon as the authors have completed revisions.

[15] Both of these effects are likely to be largest when electricity demand is high. As shown in Figures 23-26 of the Wolak RMR Study, gross RMR calls are highly correlated with total ISO load. In particular, in periods of low ISO load, gross RMR calls are very small, approximately 500 MW. During the peak periods, the gross RMR calls may exceed 3000 MW, but to our knowledge, they have not exceeded 10 percent of total ISO load.

for the 90% payback of market net revenues) may be able to increase the PX price by bidding less aggressively into the PX. It will then earn this increased price for *all* of it units, and therefore realize a net increase in profits for all of its units as a result of bidding less aggressively into the PX.

Similar logic applies to payments for providing ancillary services under an RMR contract. The payment rate for RMR ancillary services provides an opportunity cost to bidding into the ancillary services market. Generators will bid to achieve at least the expected revenue of an RMR ancillary services call. When ancillary services prices are averaging less than one dollar, even an RMR ancillary services variable payment rate on the order of $5/MW can create the insurance effect for bidding into the ISO's ancillary services markets.

There is an important distinction between the ancillary services market and the energy market that results in a differential impact of RMR contracts on the ancillary services markets. Although there are day-ahead and hour-ahead markets for ancillary services run by the ISO, there is no real-time imbalance market for ancillary services. If the ISO procures too much (or too much in the wrong congestion zone) ancillary services in the day-ahead and hour-ahead ancillary services markets and through its RMR calls for ancillary services, it cannot sell the excess capacity back into the real-time imbalance market. Conversely, if the ISO has not purchased enough ancillary services capacity to satisfy it reserve requirements in real-time, it does not have a real-time ancillary services market to which it can turn. The ISO's only option is to call more RMR capacity to satisfy this real-time ancillary services need. An ancillary services provider therefore faces no risk of having to buy back excess ancillary services quantities in the real-time market, as is the case for energy.

The ISO real-time energy market can be used to both increment and decrement generation to maintain overall system balance for energy, so that generators causing too much energy to be purchased in the day-ahead and hour-ahead markets in the wrong location face the risk that other units will be decremented in real time, which leads to lower real-time energy prices. This cost to RMR capacity of causing the ISO to over-procure ancillary services does not exist. In addition, RMR capacity benefits from causing the ISO to under-procure ancillary services because of the increased likelihood of an RMR call for energy or ancillary services to meet real-time system reliability needs. Both of these incentives cause RMR capacity to bid less aggressively (either by raising bid prices or by submitting less capacity at a given price) into the day-ahead and hour-ahead ancillary services markets in order to raise ancillary services prices or to be called to provide energy or ancillary services at its RMR contract rate.[16]

Wolak and Bushnell have explained that, because the total cost of energy dwarfs the total cost of ancillary services in almost all hours, they focused their study on the impacts of RMR contracts on the PX market. They focused on quantifying the impact of the current "A" and "B" RMR Contracts on PX day-ahead prices for the period from June through

[16] The Wolak and Bushnell study did not attempt to quantify these impacts of the RMR contracts on bids and the resulting market-clearing prices in the ancillary-services markets.

September of 1998. Their study found that total payments for energy hedged in the PX were several hundred million dollars higher during this four-month period than they would have been without the bidding behavior induced by the current "A" and "B" contracts.

The ISO Market Surveillance Unit (MSU) contemporaneously conducted an independent analysis of the impacts of the RMR contracts on market performance ("MSU RMR Study").[17] The MSU used a different methodology in its report than was used in the Wolak and Bushnell Study, but reached similar results. The MSU RMR Study found that the impact of the design of the RMR contracts substantially increased the ISO's direct RMR costs. The MSU RMR Study also concluded that both the "A Contract" and the "B Contract" influenced bidding in the PX market. The MSU RMR Study found that the exercise of market power in the PX market, i.e., bidding in excess of variable costs, resulted in higher payments for PX energy of several hundred million dollars during the June through September 1998 time period.[18]

The Committee cautions that Wolak and Bushnell estimate of the costs of the current RMR contracts on purchases from the PX is subject to significant uncertainty. Any such estimate requires a method for determining what market-clearing prices and quantities in the PX *would have been* in the absence of the current RMR contracts. This in turn requires a model for how the firms owning RMR units would bid in the absence of the current RMR contracts. Such a model can then used to construct the aggregate PX bid curves in the absence of RMR contracts necessary to compute the counterfactual market-clearing prices and quantities. The Wolak and Bushnell study constructs the counterfactual PX bid curves using predictions from an econometric model of bid prices as a function of the quantity offered under the current RMR contracts to infer how these generators would bid in the absence of the current RMR contracts. They assume that generators would bid the same aggregate quantity of energy into the PX each hour. In other words, the current RMR contracts are only allowed to influence the bid price for each quantity, not the total quantity bid.[19]

There are a variety of other reasonable assumptions that could be used to construct the counterfactual aggregate PX bid curve that removes the impact of the current RMR contracts. Wolak and Bushnell explain that they selected the assumptions necessary to construct their counter-factual aggregate PX bid curves in ways that they felt would yield conservative estimates of the costs of the current RMR contracts. However, we

17 "Report on Impacts of RMR Contracts on Market Performance," December 1998, A revised version of this report will be submitted as Attachment D when the proposed RMR Settlement is filed.

18 The MSU RMR Study did not segregate the impact of RMR contracts on PX bidding from the influence of other factors that would create market power in the PX.

19 The MSU study approaches the construction of this counterfactual aggregate bid curve from a different perspective. The essence of MSU approach is to find RMR capacity "withheld" from day-ahead schedules and put this "withheld" capacity back into the aggregate PX supply curve at that unit's average variable cost. Repeating this process for all RMR units results in the MSU's counterfactual aggregate PX supply curve, which is then used to compute the market-clearing PX prices and quantities assumes that all units are bid in at cost. MSU study is thus measuring all of the costs associated with market power, not necessarily just the costs associated with the current RMR contracts.

recognize that another analyst, applying a different methodology, would produce a different estimate of this cost. The committee welcomes such studies in order gauge the sensitivity of the cost numbers obtained by both studies to the assumptions made.

The current stumbling block to other parties performing studies is that the bid data underlying these studies has been obtained from the PX under constraints of confidentiality that preclude its release to third parties by the ISO or by the MSC. The PX has so far declined to make the full data set available either to the public or the parties to the RMR settlement negotiations, although it may be willing to make aggregate bid data available for selected days.[20] The MSC strongly recommends release to the public with a 3-month lag of all aggregate data associated with the PX and ISO markets. Selective release to certain market participants of confidential data can only benefit these market participants at the expense of other market participants and California consumers of electricity. In addition, until the data underlying these studies has been made available to the public, an analysis of the sensitivity of the resulting cost estimates emerging from these two studies to the underlying assumptions cannot be performed by other independent parties.

In any event, the MSC's opinions do not rely on the particular numerical estimates offered by either the Wolak and Bushnell study or the MSU RMR study. The precise impact of the RMR contracts on PX energy prices is less important than the fact that both studies, conducted independently using different methodologies, found significant costs associated with the current RMR contracts. Even more than these studies, the underlying economic logic suggesting that the current RMR contracts create undesirable incentives for bidding into the PX and ISO markets convinced the MSC that these contracts have the potential to impose substantial costs on buyers in the PX markets.

The MSC has met with market participants, some of whom have questioned the findings of the Wolak and Bushnell study and the MSU RMR study. They point out that under conditions of perfect arbitrage between the PX day-ahead markets and the ISO's real-time markets, assuming that no individual generator has significant market power in the PX market, and assuming that generators bid independently into the PX and ISO markets, any indirect effects of the RMR contracts on prices in the PX and real-time markets are likely to be muted. While this argument has its theoretical merits, the realities of the operation of the PX and ISO markets suggest that these conditions do not hold, leading to the conclusion that the current RMR contracts can impose significant costs on the operation of these markets. We therefore believe that the most prudent course of action is simply to reform the RMR contracts to directly eliminate the perverse incentives that they create. In this regard, we note the December 3rd opinion on the RMR contracts offered to

[20] The MSC has suggested that the PX make the bid data available to the public after a 60 or 90 day lag. Alternatively, the MSC has suggested that the data be made available to independent experts nominated by the parties to the settlement under a protective order that will protect confidentiality. The PX's Market Monitoring Committee, in its March 9, 1999 report, favored a policy of releasing aggregate PX bid data.

the MSU by Professor Robert Wilson.[21] Dr. Wilson observed that the tendency of the current RMR contracts

> to raise day-ahead prices and lower real-time prices ... can be corrected only by elaborate arbitrage -- such as UDCs [Utility Distribution Companies] 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!)."

B. Preliminary RMR Recommendations

The Wolak and Bushnell and the MSU studies made a number of recommendations in their December 1998 analyses. The key recommendations were:

1. Convert the "A" and "B" Contracts into True Option Contracts

Both Wolak and Bushnell and the MSU recommended converting the current "A" and "B" contracts, with their respective reliability payment and credit-back provisions, into a "call option contract" which eliminated both of these provisions. This RMR option contract would provide for a negotiated up-front fixed payment (that does not depend on the amount of RMR energy actually provided by the unit) to cover a portion of fixed costs and the cost of the expected number of start-ups for RMR reasons.[22] This option contract would pay only the unit's $/MWh marginal cost of production for any energy delivered under an RMR call.

2. Modify Bid Procedures for RMR Units

Wolak and Bushnell and the MSU also recommended a pair of linked changes in the procedures applicable to RMR units that bid into the PX and ancillary services markets:

a) Change the Bid/Call Sequence

Wolak and Bushnell and the MSU recommended that must-run energy needs, which are based upon load forecasts and physical system conditions, should be made public before the day-ahead energy and ancillary services markets are held. The owners of the generation that has been declared to be must-run should at this point decide whether they wish to receive, as their RMR variable compensation, their respective RMR marginal cost or the as-yet-undetermined PX price for that hour for their RMR energy. This ability to earn the market-clearing price implies a smaller up-front fixed payment for the RMR option contract.

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[21] Appendix A to the MSU RMR Report; Professor Wilson's opinion is Attachment E to this report.

[22] The MSU also suggested, as an alternative to the option contract, a series of changes to the existing "A" and "B" contracts.

b) Bid RMR Capacity as "Must Take"

The total RMR supply for each hour should then be treated in the same way as regulatory must-take capacity in the PX bid curve, for the simple reason that these units *must* operate for local reliability reasons regardless of the PX market-clearing price for that hour.[23] Bidding this quantity of electricity into the PX at a zero price guarantees that it will be sold in the PX auction.[24]An alternate approach is to require that the RMR energy from these pre-dispatched RMR units to be included in a balanced day-ahead energy schedule submitted to the ISO by a scheduling coordinator other than the PX.

C. MSC Recommendations and Analysis of RMR Contracts

The MSC concurs with these preliminary recommendations. Indeed, we believe that these changes in the RMR contracts are essential to workable competitive energy and ancillary services markets in California.

We now turn to describe in more detail the logic behind our combined recommendation of pre-dispatch of RMR capacity and must-take for this capacity in the day-ahead energy schedule.

There are two main points behind our recommendation to pre-dispatch RMR capacity and consider it must-take in the day-ahead energy market. The first is that the market clearing price in the PX should reflect the bid of the least-expensive generator that has *available capacity remaining* to supply energy. That is the lowest price that an additional unit of demand would have to pay to consume power during that hour. The second point is that the only way to guarantee that the PX does reach this desirable price is to "net" out the demand that will be supplied from RMR generation. This is achieved by requiring that all RMR generation necessary in each hour bid zero into the PX, or else be part of a balanced day-ahead energy schedule submitted to the ISO. Allowing RMR capacity to bid anything but zero into the PX implies a non-zero probability that it will not be selected in the PX auction, which contradicts the fact that this capacity is required for local reliability reasons regardless of the PX price.

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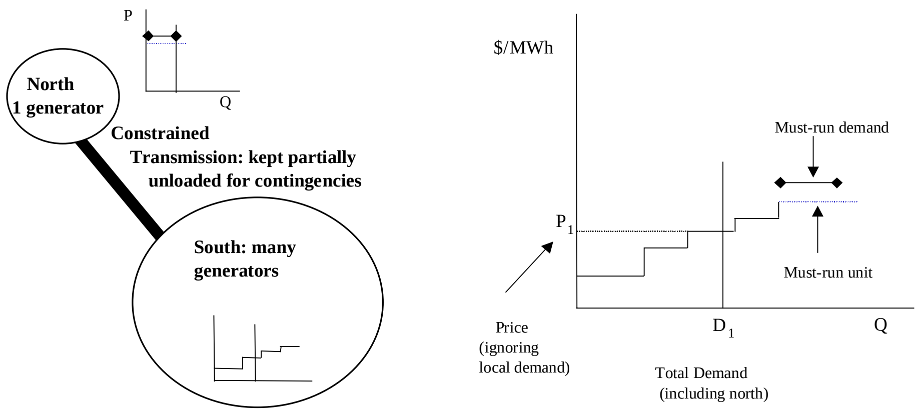
23 As distinct from the ISO's ancillary services auctions, the PX auction rules require firms to submit piece-wise linear portfolio bid functions not attached to any generating facility. Therefore, the must-take bidding requirement for RMR supply implies that that the total amount of energy bid into the PX at a zero price in each firm's aggregate supply bid curve must at least exceed its total RMR energy calls for that hour.

24 Under the current PX rules, requiring RMR capacity to bid into the PX at a zero price simply amounts to placing a lower bound on the length of the zero price segment of each RMR generator's portfolio supply bid curve. This lower bound is the quantity of gross RMR calls made by the ISO from that firm's generating units. Under the PX rules, the intersection of the PX aggregate supply curve with the PX aggregate demand curve determines the market-clearing price. Consequently, so long as it is less than the market-clearing quantity, the length of the zero-price segment in the PX aggregate supply curve is irrelevant to the level of the PX market-clearing price.

Geographic Distribution of Supply and Demand **Figure 12** **System-wide Aggregate Supply and Demand**



The first point addresses what the economically efficient price to emerge from the PX should be. The goal of an efficient market design is to bring together suppliers and consumers so that all mutually beneficial trades can be realized. Whenever there is a generator willing to sell power for a price that is less than what a consumer is willing to pay for it, that transaction should be realized. Otherwise, there are lost gains from trade, because there are buyers willing to purchase at prices greater than prices generators are willing to sell at, yet trade not take place because the market design prevents it.

Note that this does not mean that all suppliers necessarily have costs that are less than or equal to this price. There may be outside arrangements, such as bilateral trades, regulatory must-take arrangements, or reliability must-run contracts that may result in generators with costs above the market-clearing price supplying power. In most markets, trades take place at different pre-arranged prices, precisely because these trades have been arranged at different times in the past and for supply under different sorts of contingencies.[25] If at the time the day-ahead market is run, there is cheaper generation that is available and willing to sell, the market-clearing price should reflect this " "willingness to provide" under current market supply and demand conditions. The market price should not be set at the highest price arranged at some point in the past for a bilateral trade that occurs during that hour if there are other generators currently willing to supply for less. To do so would mean that some consumers, who are willing to pay more than the available generator is asking for, but not as much as this high-priced bilateral trade, would not buy power when it is socially beneficial for them to do so.

The second point has to do with how must-run generation fits into this market design philosophy. Figure 12 gives a stylized depiction of the must-run issue. (Specifically it assumes step-function bid curves, which are contrary to the PX rules requiring piece-wise linear portfolio bid functions.) The aggregate market is composed of demand in two regions, including a transmission-constrained northern region. When demand and supply in the two regions are combined into aggregate supply and demand functions, the high bid-price northern generation is not selected to supply power under a least bid-price dispatch regime. Because of the transmission constraint, however, this generation must be called upon under a must-run agreement.

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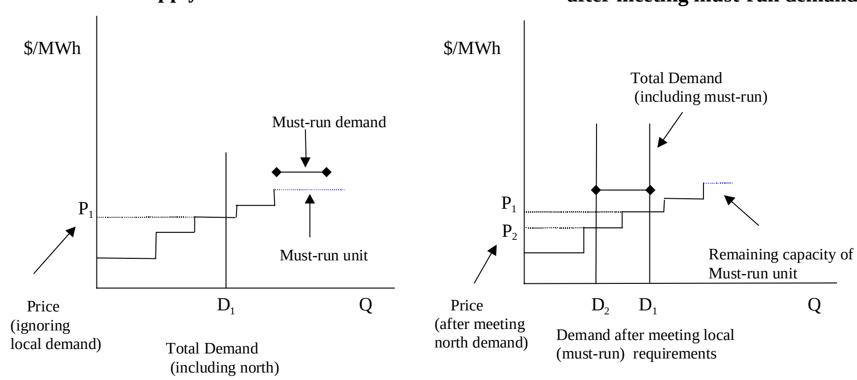
[25] An RMR contract is an example of pre-arranged contract for supply at a pre-specified price contingent on local grid reliability conditions.

If the unconstrained price were set based upon a demand level that included the demand to be met by the "must-run" unit, however, then too much power would be purchased in the day-ahead market. In other words, we would have moved too far up the supply curve when calculating the price. It has been argued that this extra generation should just be "bought-back" through a decremental bid process at a price of p_1. If this were done, however, then there would be generation that was willing to supply additional demand at a lower price, p_2 shown in Figure 13. Consumers, however, based their day-ahead purchasing decisions upon the premise that the cost of additional supply is p_1. Any consumers that were willing to pay p_2, but not p_1 for day-ahead power will stay out of this market. Mutually beneficial trades between generators and demanders will have been lost because the day-ahead price did not reflect the true price at which additional supply was available.

System-wide Aggregate Supply and Demand **Figure 13** **System-wide Supply and Demand: after meeting must-run demand**



Note that if must-run generators are allowed to bid into the PX at their variable cost, or any positive price, the above pricing anomaly will arise whenever a must-run unit has a bid greater than the economically efficient, unconstrained, price of power. It has been widely acknowledged that must-run generation is indeed often more costly than the unconstrained price – this is a major reason why it is considered must-run. Therefore, we would expect this condition to be the rule, rather than the exception. On the other hand, in those instances when the bid price of an RMR unit is less than the market-clearing price, changing the bid price for this capacity to zero will have no effect on the PX market-clearing price.[26]

Returning to the actual PX market, it is impossible, under current PX protocols, to verify if RMR capacity is bid into the PX at any non-zero price. This is because generators do not bid specific generating units into the PX. Instead, they submit portfolio bid curves and can schedule whatever generation capacity they would like for the PX quantity they

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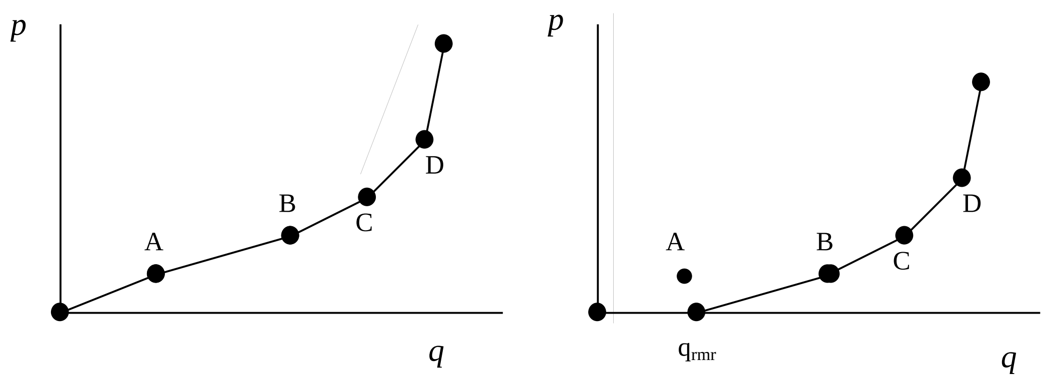
[26] There is no question that in this example the market-clearing price, *if there were no must-run units,* could be higher than the market clearing price given that there are must-run units. However, it is important to bear in mind this is not the market that actually exists. Because of local grid reliability requirements during that hour, a certain quantity RMR energy is necessary no matter what price it bids. The local monopoly power possessed the generator during this hour necessitated the signing of an RMR contract in the first place. Without some investment in new transmission capacity, load reduction capabilities, or new generation capacity, all of which require considerable capital expenditures, the need for this RMR energy remains. Consequently, in order to compare market prices with and without an RMR unit, one must factor in the cost of the investments necessary to eliminate the need for that RMR unit.

win. However, the California market design does not require generators to follow these schedules. This fact highlights the very important point that the PX is a purely financial market. Generators can bid a greater quantity of electricity into the PX than the amount of capacity they own, and firms serving load can bid a greater quantity of demand into the PX than the amount they actually serve. Indeed, firms owning no generation can submit portfolio bid curves on the supply side, and firms serving no demand can submit portfolio bid curves on the demand side. For these reasons, it is practically impossible to verify if a specific quantity of RMR capacity is actually bid in at any non-zero price.[27]

Bid Curve Without RMR **Figure 14** Bid Curve With RMR



Under the current PX portfolio bidding rules, an RMR contract only gives the ISO the right to require that a certain quantity of energy will be provided by the generating unit that the ISO needs to supply power for local reliability reasons. The owner of the RMR contract benefits from the fact that the quantity of electricity it supplies to the day-ahead energy schedule is guaranteed to be least at large as the ISO's RMR requirements from all its units, *regardless* of the shape of its portfolio bid curve into the PX.

Figure 13 illustrates the impact of the must-take proposal on an RMR generator's portfolio bid curve. The left-hand gives a generator's aggregate supply bid curve without the RMR call.[28] If the generator receives an RMR call for q_{rmr}, then the portfolio bid curve would exclude all points in price-quantity space with positive prices than have associated bid quantities less than $q_{rmr.}$ In this case, the point A is not on the new portfolio bid curve, because the quantity associated with point A is less than $q_{rmr.}$ Under the must-take proposal, the length of a generator's portfolio bid curve at zero must be greater than or equal to q_{rmr}. However, because the market-clearing price is set at the intersection of the PX supply and demand curves, if generators feel that capacity is scarce and a higher market clearing price is called for, the PX rules allow them to bid higher prices for quantities beyond their gross RMR quantity. For example, a generator wishing to set an extremely high price could submit a portfolio bid with a price of zero at its gross

27 A further complication is caused by the PX rule that all portfolio bid functions must be piecewise linear and increasing in all prices above zero. This rule makes it impossible for a participant to bid a nonzero quantity of capacity at single positive price.

28 Under the current PX protocols the piece-wise linear bid curve of any generator is constructed by connecting the bid points in price-quantity space with upward sloping straight lines.

RMR quantity and a price of $2500/MWH for 1 MW beyond this gross RMR quantity. Given that gross RMR calls have not, to our knowledge, exceeded ten percent of total ISO load, if all RMR generators submitted this same portfolio bid curve, extremely high prices could be set in the PX even during very low demand periods (although we would not expect this to occur in equilibrium in a competitive market).

It has also been argued that demand can respond in real-time to this day-ahead pricing anomaly and correct this flaw of setting the PX market-clearing price at the inefficiently high price of p_1. For example, the generator willing to sell power for a price of p_2 may find a willing customer in real-time. However, this places much unnecessary faith in the ability of both suppliers and consumers to adjust simultaneously their market positions on a near real-time basis. Clearly, loads cannot coordinate their decisions to shift their demand to and from the real-time market to eliminate these inefficient prices in the PX that result from the failure to treat RMR capacity as must-take in the PX. Even if this perfect arbitrage were possible, such a shifting of consumption from the day-ahead to real-time markets runs contrary to the design goals of the California market. It is generally thought that increasing activity--deviations from schedules--in the real time market creates additional economic costs, in terms of reserves, and reliability risks. It therefore seems counter-productive to implement a reliability must-run protocol that intentionally relies upon the movement of consumption to hour-ahead or real-time markets, particularly in the light of the desire of the ISO board and management to reduce the amount that scheduled day-ahead energy falls short of the total ISO load.

If our recommendation for RMR pre-dispatch and must-take in the day-ahead energy market is not adopted, the ISO's proposal to increase purchases of replacement reserve and charge this increased quantity of replacement in proportion to the amount a generator over-schedules, or load under-schedules, relative to its real-time obligations—the Uninstructed Deviation and Replacement Reserve Allocation plan described earlier—will create a windfall to generators in the form of higher PX and real-time prices. This windfall occurs because the ISO's proposal increases the cost of the demand-shifting activity across markets that is necessary to arbitrage the inefficiently high PX prices arising due to the failure to treat RMR capacity as must-take.

There are reasons to believe that demand-shifting to the real-time and hour-ahead markets cannot completely eliminate consumer welfare losses resulting from the inefficient price setting process that yields p_1. To mitigate these effects completely, buyers in the PX need to know exactly how each pre-dispatched RMR unit will bid, and from this impute how much RMR electricity will be priced above the market-clearing price and spill over into real time. Only with complete information on the RMR spillover can the buyers shift demand exactly to minimize purchase costs across the day-ahead, hour-ahead and real-time markets. Even if we assume perfect foresight on the part of all participants, buyers still face the difficulty of coordinating their shifts in demand across these markets.

Consequently, pre-dispatching the RMR capacity and requiring it to bid into the PX at a price of zero will yield efficient market prices for day-ahead energy under the realized contingency that specific RMR units are must-run (and therefore must-take) during that hour for local grid reliability reasons.

The likely impact of this pre-dispatch and must-take rule on PX prices is extremely difficult to determine because generators and loads will most likely change their bidding strategies in response to this new protocol for calling RMR capacity. Given that demand will no longer have to guess which market—the day-ahead, hour-ahead or real-time market—RMR energy will show up in, we would expect energy prices in these markets to be less volatile. However, it is unclear if average PX prices will fall as a result of this rule change. One example of how this rule change might have no effect on PX prices is if the quantity of energy each generator won in the PX auction exceeds the total amount of RMR generation it supplied during that hour. Applying this rule for bidding RMR generation into the PX to these same supply and demand bids will reproduce the actual PX market-clearing price and quantity. Only during hours when there exists a generator who has won less energy in the PX than the total amount of RMR energy it supplied in that hour would a different PX price result from implementing this rule for bidding RMR generation into the PX using actual bids.

As noted above, the most likely outcome of this rule change is to reduce the volatility of prices. There will be less zeros in the PX market (because demand bid too aggressively into the PX relative to the aggregate supply curve submitted) and less extremely high prices (because demand did not bid aggressively enough relative to the supply curve submitted). Less volatile energy prices and less reliance on the real-time markets should increase the efficiency of the PX and ISO energy markets, benefiting both generators serving the California market and California electricity consumers.

D. MSC Analysis of the RMR Settlement Proposal

The proposed RMR settlement is scheduled to be filed shortly with the FERC. The Committee has not reviewed the final text of the settlement, and can offer only preliminary views, which it may supplement in a later report.

1. RMR Settlement Proposal

The settlement, as it has been outlined to the Committee, has the following substantive elements:

a) New Form of RMR Contracts

Effective May 1, 1999, the “A” and “B” contracts will be replaced by a new contract which eliminates the reliability payment and the credit-back provisions of those contracts, and which provides for an up-front payment to cover fixed costs and for start-up and variable costs payments when the unit is called.

b) Timing of RMR Calls

The current ISO tariff provision for calling the RMR units after the PX day ahead market closes, and the provision that allows RMR unit owners unfettered discretion in bidding into the day ahead and hour ahead markets, are retained for now. However, the ISO is permitted not earlier than October 1, 1999, to make a unilateral tariff change to reverse the bid/call sequence and to require called units to bid into the PX as must-run units (i.e., at a zero price). This change would take effect on December 1, 1999, unless FERC suspended it.

c) Procedural Steps

The generators cannot file at FERC to change the RMR contracts until 2002, except in response to the ISO's October 1st filing described above or in response to certain emergency filings the settlement allows the ISO to make.

2. MSC Analysis

The Committee makes the following observations respecting the RMR contracts and the proposed RMR settlement.

1. The Wolak and MSU RMR studies recommended that the RMR contracts be modified to remove the reliability payment and credit-back, to modify the bid/call sequence, and to require RMR units be bid into the PX as must-run (or be part of balanced schedules). The Committee believes that the entire set of recommended changes in the RMR contracts should be implemented as soon as possible.

2. The settlement appears to move toward a system of call-option contracts, per the December recommendations, and the Committee supports this aspect of the settlement (as it has been communicated to us).[29] On the other hand, the settlement, does not implement the changes in bidding procedures effective May 1, 1999. Rather, it provides a mechanism by which the bid/call sequence and bidding procedure can be modified, effective December 1, 1999.

3. Under the proposed settlement, RMR unit owners, if they anticipate that they will be called under their RMR contracts and that PX prices will be lower than their variable cost, will still have incentives either to stay out of the PX market or to push up the PX market clearing price to the level of the unit's variable cost payment under the RMR contract. However, the elimination of the reliability payment and the credit-back would appear to reduce the price effect of this bidding behavior.

4. The Committee would prefer a settlement that implements all the changes on May 1, 1999. If the Commission approves the settlement, the Committee recommends that the Commission condition its approval on the ISO's (a) exercising its authority under the settlement to file the further changes on October 1, to be effective December 1, and (b) keeping the $250 price caps on real-time energy and ancillary services in place until these further changes take effect.

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VI. PRICE CAPS

A. Ongoing Need for Price Caps

As the Committee stated in the August MSC Report, "the ultimate goal of regulators and stakeholders is to let market processes determine the prices for electricity services in California". However, the Committee believed at the time that "it is clear that there are currently flaws in the design and implementation of these markets" and that "until the most significant market problems are corrected the need for damage control caps remains."[30] The Committee's further analysis and review have demonstrated that the linkages between the various ISO and PX auction markets required comprehensive and carefully coordinated action to redesign these markets and the RMR contracts before the price caps can be lifted. There are three reasons for this conclusion:

First, because the same generation units serve both energy and ancillary services markets, any change in the price caps for the various services must be in parallel. Retaining caps in some markets, but not all, will divert bids from the capped to the uncapped markets, further distorting competition in the California markets.

Second, before the price cap on real-time energy can be raised, the RMR contracts must be restructured so that they do not distort bidding incentives for owners of RMR units. Currently, the price cap constrains the PX day-ahead and hour-ahead market clearing prices to levels below $250. Unless the full set of RMR reforms is in effect, the ISO cannot be confident that RMR owners will be unable to raise prices in the PX markets above competitive levels once the real-time energy price is permitted to go above $250.[31]

Third, removal of the caps on ancillary service bids requires completion of the necessary ancillary service redesign initiatives, including implementation of the rational buyer protocol to reduce the likelihood of market perturbations.

B. Necessary Conditions for Raising the Price Caps

The Committee strongly recommends raising the current $250 caps on real-time energy and ancillary services from $250 to $2500, in two phases, as soon as these markets and the PX markets are workably competitive.

1. Phase I: $750 Price Cap

We believe that the caps can be raised to $750 once the following measures are implemented:

- Rational Buyer Protocol
- Ancillary Services Redesign as per the ISO's March 1, 1999 Filing
- Full Reformation of the RMR Contracts, Including

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[30] See the August MSC Report at pages 52-53.

[31] The current RMR contracts may also affect prices in the ancillary services markets.

- ✓ Removal of Reliability Payment from "A" Contract
- ✓ Removal of Credit-Back from "B" Contract
- ✓ Reversing the Bid/Call Sequence
- ✓ Requiring RMR Units to Bid into the PX as Must-Run.

2. Phase II: $2500 Price Cap

Once these measures have been implemented and the ISO and PX have been through a summer peak season without major observed market dysfunctions, we recommend that the price caps be raised to $2500, the level of the cap currently applicable in the PX markets.

C. Safety Net

The ISO currently has authority to set a damage control cap and to change it from time to time. We recommend that this authority be retained for the foreseeable future. However, the ISO as a matter of policy should not intervene to change caps from the recommended $750 and $2500 levels except in the most compelling circumstances.

We have reviewed the ISO's Safety Net proposal under which it would retain authority to modify the damage control caps. In its March 1, 1999 FERC filing, the ISO described a Safety Net procedure to manage and guide ISO responses to future market crises in the ISO markets. The proposed procedure is to take effect at the same time that the present level of price caps on the real-time energy and ancillary service capacity markets are raised. Under the Safety Net procedure, ISO Management may lower price caps on real-time energy and ancillary services capacity in response to strong evidence of serious flaws in the California marketplace. In the event of a market crisis, the ISO Management would take such action pending ratification by the ISO Governing Board. The continuation of the action would then require ratification of the ISO's Governing Board at the earliest possible opportunity, and would be followed by a program to investigate the cause(s) of the crisis, develop appropriate design changes, with price caps to be raised upon implementation of the design changes.

The proposal includes an overview of an observation program to detect the flaws that might trigger the use of the Safety Net. The proposed observation program is based on the underlying principle that under competitive market conditions the bid prices (and therefore, the market clearing prices) reflect marginal costs (including opportunity costs). Accordingly, the Safety Net observation program includes two indicators that the MSC believes are particularly important: (1) a sudden and sustained significant change in the market clearing prices with no comparable change in system conditions, and (2) insufficient bids to meet the ISO's need for capacity and energy, despite indication of adequate supply. The Safety Net proposal is a potentially useful addition to the ISO's toolbox for responding to emerging problems in the markets for energy and ancillary services, and the MSC recommends that the proposal be pursued.

The Committee believes the ISO's proposal strikes an appropriate balance between the need to protect the market from events like last July's price spikes, on the one hand, and the need to avoid unnecessary market intervention, on the other. The MSC anticipates working with the ISO on the further development of the proposal's observation plan. However, the MSC reiterates its earlier recommendation that the ISO exercise considerable restraint in its future use of authority to lower price caps. High prices can be an important signal to market participants to augment supply or shift demand. This signal should not be muted without compelling evidence of serious damage to the market.

VII. SUMMARY OF RECOMMENDATIONS

A. Ancillary Services

The Rational Buyer Protocol and other changes proposed in the ISO's March 1st filing are necessary for properly functioning ancillary services markets. Although the settlement procedures proposed by the ISO under its Rational Buyer Protocol are less than ideal, we recommend that the Commission approve these changes.

B. RMR Contracts

We regard the proposed settlement respecting the RMR contracts as an important first step in the reformation of the contracts and recommend its approval. However, mitigation of the market effects of the current contracts also requires changes in the ISO's bid procedures (reversing the bid/call sequence and bidding RMR units as "must-run") that will not take effect under the settlement until December 1, 1999, at the earliest. Accordingly, we cannot conclude that the ISO and PX markets will be workably competitive until this second step has been effectuated.

C. Price Caps

We recommend that the ISO's authority to impose "damage control" caps on real-time energy and ancillary services be retained for the foreseeable future. However, the current \$250 caps should be increased to \$750 as soon as the measures recommended above (rational buyer, the other March 1st market redesign proposals, and RMR reform) are fully implemented. The caps should be increased to \$2500 as soon as a summer peak's experience shows that these changes are sufficient to ensure that energy and ancillary services markets are workably competitive. Finally, we recommend that the ISO adopt polices designed to avoid lowering the caps, once raised, except in the most compelling circumstances. The ISO's "Safety Net" proposal is consistent with that objective.

ATTACHMENTS

A. August MSC Report

B. November MSC Opinion (BEEP Cap)

C. Wolak Study

D. MSU RMR Study

E. December 3, 1998 Opinion on RMR Contracts by Professor Robert Wilson