Preliminary Report On the Operation of the Ancillary Services Markets of the California Independent System Operator (ISO)

Prepared by the Market Surveillance Committee of the California ISO*

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Summary of Findings and Recommendations

The Market Surveillance Committee of the California Independent System Operator has conducted a preliminary review of the performance of the ISO's ancillary services markets, and offers here recommendations for improving that performance. Further and more definitive recommendations must await additional market experience and further data analysis, as these markets remain in a state of flux.

The Committee finds that the ISO's ancillary services markets do not yet operate in a manner consistent with workable competition. Compared to the Power Exchange (PX) and supplemental energy markets, prices in the ancillary services markets do not fluctuate in a manner that reflects changes in the underlying marginal costs of supplying these products. Ancillary services markets have exhibited extreme price volatility, even during periods when demand was unchanged for long periods of time. The conditions are 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 exceed the prices for higher quality services such as regulation. Often ancillary services capacity prices exceed both the power exchange and real-time energy price for the same hour. Until workable competition has been established, the Committee recommends that the ISO continue to utilize a price cap for ancillary services.

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

While we have not been able to precisely measure the relative significance of each of these problems, preliminary analyses do provide some insights. The quantities of ancillary service purchased have far exceeded the levels at which they have historically been acquired. High demand is 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 have routinely exceeded those for 'superior' services. The lack of substitution in the consumption of these services therefore appears to have significantly impacted the cost of acquiring them. Lastly, it appears that RMR copntracts are not doing much to reduce market power problems, and are most likely contributing to them. Our preliminary results indicate that RMRs provide an incentive to withhold generation capacity from these markets.

The Committee recommends to the ISO the following specific remedies to enable the ISO's ancillary services markets to become workably competitive: (1) adopt rational and transparent purchasing practices for ancillary services, seeking additional regulatory flexibility as needed; (2) revise and supplement the reliability must-run contracts; (3) support the move towards market-based rates for all market participants, using the requirement that owners of significant amounts of generation capacity sign financial contracts for differences to mitigate their incentives to exercise market power in these markets; (4) retain the authority to impose a "damage control" price cap and exercise that authority until these markets are demonstrably competitive; (5) purchase ancillary services using a state-wide auction, using reliability must run constracts to supplement zonal shortfalls in capacity from this market-clearing mechanism and (6) revise purchasing protocols to help reduce the need for regulation services.

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1. Introduction

This report summarizes the observations and recommendations of the market surveillance committee (MSC) of the California Independent System Operator (ISO) concerning the current design and operation of the ISO's ancillary services markets. On June 30, the Federal Energy Regulatory Commission (FERC) granted permission for three generation units owned by AES Corporation to earn market-based rates for the sale of ancillary services in California. Similar permission was subsequently granted to other generation units recently divested from the incumbent investor-owned utilities. Over the following weeks, these markets experienced enormous price swings within and across days. On July 17, FERC rejected the request of the ISO and other market participants to stay FERC's decision granting these firms market-based rates, but upheld the ISO's authority to set a maximum price at which it will purchase ancillary services (the "price cap"). The July 17 order also requested that the market surveillance committees of both the ISO and the California Power Exchange conduct an independent review of these markets.

This document provides a qualitative description and analysis of the ancillary services markets. The short deadline for preparing the report and initial software problems associated with extracting the large amounts of necessary data from the ISO's internal databases prevented the MSC from undertaking a comprehensive quantitative analysis of the performance of these markets over the months of June and July. To supplement its data analysis, the MSC and the ISO's market surveillance unit conducted joint telephone interviews with representatives from the majority of the large market participants to understand their perspective on the shortcomings of the current design and operation of the ISO's ancillary services markets. In addition, an open meeting of the MSC was held on August 12th to solicit further input from market participants and other interested parties. We are grateful to these individuals and organizations for their valuable input. Our report is based on the empirical analysis of market data we have been able to able to perform up to the present time, input from market participants, and our discussions with the staff and consultants to the market surveillance unit of the ISO.

This report identifies several factors that we believe have created problems with these markets that have been much more severe than those experienced in the energy markets of both the ISO and the PX. It is important to note that significant changes have taken place in these markets during the last month, and these markets remain in flux. Thus, any analysis of ancillary-services markets in California at this time must be viewed as preliminary. Both the market surveillance committee and the market surveillance unit of the ISO are continuing to perform further quantitative studies. The MSC is currently undertaking more detailed analyses of the vast amounts of data now available from the ISO's Market Surveillance Unit. We are hopeful that these ongoing studies will shed further light on the performance of these markets, the relative significance of the various factors identified below, and on the potential benefits of the proposals discussed in this report. We understand that an opportunity will be provided for public comment on this report. The Committee intends to review those comments and to revise or supplement this report as appropriate.

It is not our intention in this report to attribute “blame” for the recent market disruptions to any firm or set of firms. Such an assessment would, among other things, entail a detailed examination of bidding behavior that we have not had the time, resources, or, until very recently, the necessary data to perform. Additionally, because the market is continuing through a transition period, it would be premature to state that any firm has achieved “sustainable” market power. We also do not claim to provide an exhaustive list of the individual problems that plague these markets. There are many implementation difficulties, notably technical and software problems, that we do not feel qualified to comment on at length. We are instead trying to assess the overall functioning of the market. This report therefore focuses on what we feel to be the major problems relating to the design, implementation, and regulation of these markets.

The committee wishes to reaffirm its confidence that *properly functioning* market processes can effectively set prices in the electricity industry. At the same time, we also recognize that in the process of assembling a complex set of interactive market protocols under short time deadlines, serious flaws are almost inevitable. Some of these flaws can result in market disturbances that, at times, make necessary some form of intervention into the market. The hope of this committee, and most all market participants, is that the most serious flaws can be corrected as quickly as possible, thereby greatly reducing the need for intervention. The Committee would like to emphasize, however, that the a true market system in electricity, as in telecommunications and other industries undergoing the transition from regulation to competition, cannot be achieved overnight; during the transition period, dangers arise if some participants are afforded the flexibility we associate with the market system while others remain subject to restrictive rules.

In Section 2, we provide an overview of the ISO ancillary services market design as it was originally conceived. We also point out that the implementation of the ISO’s markets has differed from the intended design in several significant ways. In Section 3, we give an overview of the ancillary services market performance over the period of its operation, breaking out three distinct time periods for our analysis. Section 4 analyzes the structural problems that have plagued these markets and contributed to the difficulties experienced in these markets to date. In Section 5, we present several proposals for revising the design and implementation of these markets. Section 6 offers conclusions.

2. Design Philosophy of the ISO's Electricity Product Markets

In this section we describe the ancillary services product markets that are operated by the ISO. We focus here on the *intended* operation of these markets, i.e., the way these markets are described in the ISO tariff and protocols. In fact the operation of these markets currently differs from the intended design in several important ways. The impact of these differences will be the focus of later sections.

The California ISO has responsibility for implementing and monitoring markets for several products. Electrical energy is not, technically, one of those products. In theory, the ISO's role is one of "gatekeeper" to the underlying central market for electrical energy. As the gatekeeper, the ISO is responsible for assuring that all qualifying traders have access to whatever suppliers and customers of electricity that they wish to transact with. In the process of providing such access, the ISO is responsible for acquiring a variety of reserve, or "ancillary services," monitoring and billing traders that consume these services, and operating a *de facto* market for transmission congestion management. In this report we concentrate on the ISO's responsibilities for acquiring, dispatching, and charging for ancillary services.

The focal point of the ISO operations is in many ways the market for energy "imbalances." The term imbalance refers to a discrepancy between the amount of energy a trader, or scheduling coordinator (SC), has told the ISO in advance it will provide or consume, and the amount that it actually supplies or consumes in real-time. That is to say, any power that was supposed to be provided by an SC, but was instead procured by the ISO, is billed to that SC at the going rate for imbalances. In this sense, the imbalance market can be viewed as the true spot market for power, since it represents the instantaneous cost of procuring the commodity electrical energy.

2.1. Ancillary Service Markets

The ISO is responsible for acquiring or monitoring the acquisition of 6 ancillary service products. These products and the corresponding service requirements are listed in Table 1.

Product	Performance Requirement	Proposed Quantity Supplied
Regulation Reserve	Instantaneous: automatically controlled by the ISO	Operator's discretion Historically about 3% of load
Spinning Reserve	On-line, produce within 10 min	Sum of both spin sources equals approximately 6.7% of load
Non-spinning Reserve	Off-line, produce within 10 min	
Replacement Reserve	1 hour	Difference between scheduled and ISO forecast demand[1]
Voltage Support/Reactive Supply	As needed	As needed
Black Start	WSCC standards	WSCC standards

Table 1: Ancillary Service Products

Of these six ancillary services, the last two, voltage support and black start, are not acquired through a day-ahead hourly market-clearing process. These are instead procured through a longer term contracting process. This could be an option for some of the other services, as we discuss later. In this report, we will focus on the other four services. On the day before these services are required, the ISO holds auctions for each service, determining a market-clearing capacity ($/MW) price for each. Thus, in theory, successful bidders into these markets will be rewarded for making capacity available to the ISO to provide power under certain conditions and requirements. Successful bidders into each of these markets may or may not in fact be called upon to provide energy. As we will discuss later, the conditions under which units bidding into the spin and non-spin markets may be called to supply imbalance energy are currently somewhat ambiguous. If these units are called upon to provide real-time energy, suppliers to the spin, non-spin, and replacement reserve markets are paid the imbalance energy price for any energy that they provide. This payment is *in addition* to the capacity payment they receive for making their capacity available to the ISO. Due to metering and software limitations, suppliers of energy into the regulation market cannot set or earn the imbalance energy price for any energy that they provide.[2] Suppliers of regulation energy instead earn the Regulation Energy Payment Adjustment (REPA), a dollar per MW of regulation capacity bid payment that is set according to an *estimate* of the energy provided by each supplier.[3]

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[1] Until recently, the ISO capped its replacement reserve purchases at 1000 MW.

[2] This is a departure from the original design of the regulation market.

[3] Proposed Amendment 8 to ISO Tariff filed May 19, 1998, conditionally accepted June 24, 1998 in Order Accepting Proposed Tariff Amendment for Filing, Providing Clarification and Guidance, 83 FERC 61

Suppliers bidding to provide any of these four ancillary services must satisfy various technical operating characteristics for each of these markets. Bidding in each market consists of a capacity price ($/MW) and a schedule of energy price ($/MWh) and quantity (MWh) bids. In selecting the "winners" of each market auction, the ISO selects suppliers in increasing order of their *capacity* prices ignoring, their energy price bids.[4] The market clearing ancillary service price paid to all winning bidders not subject to cost-based price caps is set at the capacity price bid of the last bidder whose capacity is accepted. Those winning bidders subject to cost-based price caps are currently paid their bid price for the quantity of each ancillary service that they supply to the market. An important feature of the operation of these markets is that although firms submit their bids to all of these ancillary services markets simultaneously, the markets clear sequentially, with regulation first, followed by spin, non-spin, and finally, replacement. All four markets are cleared and bidders are told the market clearing prices and how much of their capacity was accepted for each market. In this sequential market-clearing process, capacity that is won in a previous auction is subtracted out from the capacity that is bid into the subsequent markets. For example, if a participant bids 100 MW of a generating unit into regulation and 200 MW into spin and wins 50 MW in regulation at the regulation bid price, then 200 MW – 50 MW = 150 MW is actually bid into the spin market at the spin bid price. If 80 MW is won in the regulation market, then only 120 MW is actually bid into the spin market at the spin price. If 100 MW is bid into regulation and 50 MW is bid into spin, even if *none* of the 100 MW of bid into regulation is taken in the regulation market, only 50 MW is bid into the spin market. The impact of this feature of the current market-clearing protocol on the efficiency of the ancillary services market will be discussed later in this report.

A final important feature of the ancillary services markets that affects the incentives of bidders in these markets is the mechanism used to pay for ancillary services. Currently, the ISO charges SCs for their share of the total costs of the four ancillary services procured from these four markets based on each SC's share of total scheduled energy. However, the cost ancillary services provided under an RMR contract is charged to the transmission company local to that facility. This difference in the payment mechanism for ancillary services based on whether or not they are purchased through the market or under an RMR contract should affect the incentive of generating companies differentially depending on the amount of transmission facilities they owns and whether they are a net demander or supplier of electricity.

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[4] When there is a capacity price tie for the right to provide ancillary service capacity, instead of choosing the producer with the lowest energy price, the capacity award is allocated equally among all producers involved in the tie.

2.2. Imbalance Energy Market

Operation of the imbalance energy market, while not technically an ancillary service market, nevertheless constitutes an important commercial function of the ISO. The imbalance energy price is, in practice though not in name, a spot price for energy in the ISO system. The imbalance price, which is calculated at 10-minute intervals, 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[5] (or reduced demand) will earn this price and those providing extra demand (or under supply) will pay it.[6]

The ISO acquires energy from any one of five sources: from the four hourly ancillary services markets, and from suppliers who bid to provide "supplements" to their day-ahead energy schedules. As described earlier, suppliers who have committed capacity to one of the ancillary service markets, excepting regulation, 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 payment only.

Each ancillary services provider will have submitted 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.[7] 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. A decremental bid represents a price that a generator or load source would pay to the ISO in exchange for the right to either reduce supply or increase demand. When supply exceeds demand, the ISO calls on the highest priced decremental bid to restore balance. The 10-minute imbalance price is set at the price of the last, or marginal, unit of supply or demand that was called on to adjust its schedule. In the case of undersupply this would be the highest incremental bid taken. In the case of oversupply this would be the lowest decremental bid. All instructed deviations from a generator's schedule, those ordered by the ISO in real-time as it moves up or down the supplementary energy bid stack, are

[5] The difference between scheduled and actual supply will also reflect an updated scaling factor to account for transmission losses. Supply adjustments for transmission losses are discussed in more detail below.

[6] Although the imbalance price is updated every 10 minutes, the system is initially capable only of tracking imbalance *quantities* once an hour. The settlement charges currently are thus based upon the average of the six imbalance prices from each hour.

[7] We assume, for simplicity, there is no congestion. If there is congestion in the real-time market, then prices are set on a zonal basis.

settled at the 10-minute price in force when the instruction was given to the generator. All generators supplying electricity during a given hour can also make uninstructed deviations from their schedules in real-time for economic or unit reliability reasons. However, the ISO is only able to measure deviations from hourly generation schedules. Currently, these hourly uninstructed deviations up or down relative to a generator's hourly schedule are settled at the average of the six 10-minute prices relevant for that hour. This price is referred to as the hourly real-time energy price.

2.3. Ancillary Services Market Prices Under Ideal Conditions

Before describing the market outcomes experienced to date in the ISO's ancillary services markets, it is useful to consider what we would expect the relationship between the prices in these various markets to be under ideal circumstances. By "ideal circumstances," we mean at least five specific conditions hold: (1) no market participant has market power; (2) transactions costs are minimal; (3) suppliers and consumers are risk neutral; (4) there are no physical, regulatory, or software-based entry barriers that restrict the pool of potential suppliers in any of these individual markets; and (5) the ISO has the flexibility to act as a rational buyer, including the authority to enter into contracts with suppliers to serve its anticipated needs for ancillary services. We stress that these conditions represent *ideal* circumstances, and are unlikely to be fully met in practice; however, we are confident that the closer actual conditions in the ISO's ancillary services markets come to these ideal conditions, the greater is the likelihood that these markets will bring the full benefits of competition to California electricity consumers.

Under these ideal conditions, we would expect prices in each of the ISO's markets (as well as the PX) to equilibrate so that suppliers to any of one these markets would expect to earn roughly the same amount of variable profit (total revenue less total variable costs) regardless which market they choose to bid their generating capacity into. Thus, under ideal circumstances we would not expect any significant arbitrage opportunities between these markets from shifting generating capacity across these markets within the day and across days.

Under these conditions, the equilibrium capacity price for supplying non-spinning reserve and replacement reserve should be very close to zero if two additional conditions are met. These are: (1) the facilities supplying capacity in these two reserve markets and generators bidding into the supplemental energy market are both dispatched in the real-time energy market according to their energy price bids only[8] and (2) there are bids made into the supplemental energy market.[9] If one of these ancillary service prices *w*

[8] There may be some additional cost to selling real-time energy by first supplying capacity to the ancillary services market as opposed to simply bidding into the supplemental energy market. These costs would be reflected in the reserve capacity prices, but do not appear to be significant.

[9] Unlike the five conditions listed above, these conditions are often met under current market operations.

substantially greater than zero, we would expect generators bidding into the supplemental energy market to instead bid into the high-priced reserve market. This is because generators can sell imbalance energy through both the reserve markets and supplemental energy bids on a roughly equal footing. A generator could therefore earn a significant capacity price *in addition to* the same expected imbalance energy sales by moving its capacity from the supplemental energy market to the replacement reserve market. This process would continue until there were either no more generating units willing to bid into the supplemental energy market, or the market-clearing capacity price in both of these markets is close to zero. In fact, under these conditions, only a shortage of capacity or the exercise of market power could keep the price of these reserves substantially above zero on a regular basis.

If these ideal circumstances did hold, and there were no market power detected in some of the markets, then the potential for any firm to exercise market power would be minimal in *all* of these markets. In other words, if there were little or no market power detected in the PX or imbalance energy market, there should little or no market power in the ancillary services markets. However, over the last month or so, just the opposite has been the case. While it is too early to make a final determination about the competitiveness of the energy markets,[10] it is clear that prices in the energy markets have not risen as far, or as consistently, above estimates of marginal costs as they have in the ancillary service markets.

Specifically, prices in the ancillary services markets routinely far exceed the prices in day-ahead energy market operated by the Power Exchange and the real-time energy market operated by the ISO. This occurs despite the fact that the cost of providing ancillary services capacity from a generating unit is presumably less than the cost of providing energy from that same unit. Recall that the ancillary services capacity payment requires a unit to stand ready to produce electricity with some time lag, whereas selling into both the PX and the real-time energy market requires the plant owner to actually produce electricity. In providing some reserves, particularly regulation, units can suffer considerably more wear and tear than they would providing energy at a constant level. The provision of regulation and spinning reserves also entails operating a unit at a level below it most efficient output point. We therefore cannot predict *exactly* what the relationship between ancillary services prices and energy prices should be, even under ideal conditions. It is reasonable to assume, however, that the price of regulation and spin should be somewhat related to the real-time price of energy. The price of non-spin and replacement reserve, which do not require the generating unit to be running during the hour its capacity is made available, should be lower than the price of regulation and spin and often approach zero.

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[10] In many electricity markets around the world, severe market power problems are only experienced during times of high demand. The California market has only recently entered its highest demand period, and energy prices have risen rather quickly. Therefore a full assessment of any market power problems will require observing the behavior of the market throughout this period of high demand.

Therefore, one indication that the ancillary services markets may not be functioning as well as they could be would be very high prices for non-spin and replacement reserve. Furthermore, we would expect the prices of the ancillary services to reflect the relative costs of providing those services. As we discuss below, it is reasonable to assume that the costs of providing ancillary services is declining with the 'stand-by' requirements imposed by providing those services. Providing regulation should therefore cost more than providing spinning reserve, providing spin should cost more than providing non-spin, and providing non-spin should cost more than providing replacement. In a properly functioning market, prices for these services should follow the same pattern.

3. Performance of Ancillary Services Markets

Price movements in these markets have fallen into at least three distinct periods. The first period, March 30 to June 30, was dominated by regulatory effects. The second period, roughly June 30 to July 13, was characterized by severe price volatility and confusion while prices during the last period, from July 14 to the current date were clearly influenced by ISO imposed bid caps. We will discuss each period more detail below.

Date	**Event**
March 30	Market opens.
May 20	Regulation Energy Payment Adjustment (REPA) is implemented for regulation energy.
June 10	Order issued for new cost-based rates for some divested units.
June 30	AES granted market-based rates, all firms made eligible for market-based rates on replacement reserve.
July 10	Dynergy and Houston Industries granted market-based rates.
July 14	$500 price cap imposed by ISO on all ancillary services.
July 24	ISO price cap revised to $250.
August 6	ISO begins accepting bids for spin, non-spin and replacement for units out of the ISO control area.

Table 2: Important Dates in the Ancillary Services Markets

Because the ancillary services markets from March 30 to June 30 were dominated by the widespread imposition of cost-based caps on the prices received by firms bidding into these markets, there is very little difference in the performance of these markets across months during this time period. Consequently, we reduced the length of our pre-market-based rates control period to June 1 to June 30. All figures presented in the remainder of this report are for the following three time periods: (1) June 1 to June 30: prior to the granting of market-based rates; (2) July 1 to July 13: market-based rates granted for some participants; and (3) July 14 to July 31: imposition by the ISO of a price cap on ancillary services.

Ancillary services are often procured on a zonal basis because of anticipated congestion between North and South of Path 15 (NP15 and SP15). This process often results in different prices for each service for the two geographic zones. We therefore present separate plots for the prices of the four services North and South of Path 15. All of plots discussed in this section have the same scale on the vertical axis for each of there time periods in order to make it more straightforward to assess whether there are changes in hour-to-hour or day-to-day volatility of a given magnitude across the three time periods.

3.1. Basic Data on Market Performance

Figures 1 and 2 present plots of the hourly *prices* North and South of Path 15 (NP15 and SP15), respectively, in the four ancillary services markets broken down by our three time periods. We truncated the scale of these plots at $250/MW in order to better reveal the movements in prices over time in the $0 to $50 range. Values in excess of $250 are simply plotted as $250. Thus, the Figures do not show the sequence of prices from Hours 14 to 18 in the Replacement Reserve Market on July 9 of $2,500, $5,000, $5,000, $5,000, $750. They also do not show the price sequence in this same market for Hours 14 to 18 on July 13 of $9,999, $9,999, $9,999, and $9,999.[11] Across the top of each graph we plot an indicator variable, CONGESTION. The hours that this variable appears at the top of each plot as a "+" denotes those hours when ancillary services were procured on a zonal basis.

Figures 3 and 4 present plots of the hourly *quantities* purchased of the four ancillary services for the three time periods for North and South of Path 15, respectively. Once again, the indicator variable, CONGESTION, shows those hours when ancillary services were procured on a zonal basis.[12]

Figures 5 and 6 present hourly bid sufficiencies for our three time periods for North and South of Path 15. We define "bid sufficiency" as the total capacity submitted in a given hour divided by the ISO's total needs during that hour, measured in percentage terms. A bid sufficiency value of 100% indicates that *just* enough capacity was bid to serve the ISO's needs. A bid sufficiency value of less than 100% indicates that the ISO was unable to cover its demand for that ancillary service from bids submitted to the market. A bid sufficiency value of 1000% indicates that ten times as much capacity was bid into the market as the ISO required. Following our convention for plotting extremely large values of variables, we truncated the vertical axis of our plots at 1000%.[13]

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[11] Increasing the scale of the graphs to include these values would completely obscure any movements in prices in the $0-$50 range, which contains the vast majority of the prices.

[12] Data for June 10 for the hourly quantities demanded for all ancillary services were missing from the data set provided to us by the Market Surveillance Unit of the ISO. We chose to plot all of these quantities as zero for all for markets for all hours during that day.

[13] Information is lost by this truncation, since during many hours, enormous bid sufficiency values occurred. These hours appear in the graphs as a value of 1000 in order to better illustrate the variation in bid sufficiencies around the very important 100% level. Increasing the scale on the vertical axis to capture values of bid sufficiency on the order of 5,000% would make the graph virtually useless for

There are several general features of these graphs that are worth noting before we focus on features unique to the three time periods. First, except for the North of Path 15 price graph for the time period July 1 to July 13, there is a tremendous amount of price volatility in these markets. This is true for all of the markets. For example, on Hour 13 of July 9, the hour before the price of replacement reserve hit $2500/MW South of Path 15, the market cleared at a price of $1/MW, despite the fact that the ISO sought 500 MW of replacement reserve for all hours of the day. On July 13, the price of Replacement Reserve in Hour 17, the hour immediately following the string $9999/MW prices, was $0.01/MW.

In order to illustrate the amount of price volatility in these markets, in Figures 7 and 8 we constructed a histogram of prices in each of these markets for each of the three time periods for North and South of Path 15. These histograms give the frequency with which prices in each of the four markets fall into the four ranges: $0 to $50, $50 to $150, $150 to $250 and greater than or equal to $250. The striking feature of these histogram is the almost complete lack of prices in the intermediate, but by no means low-priced, range of $50 to $150. For all markets and time periods except the non-spin market South of Path 15 from July 14 to July 31, this range of prices contains the smallest fraction of the total number of prices for that time period.

The second feature of these plots is the relatively small amount of variation in demand across hours in the day for the spin, non-spin and replacement reserve market. For the replacement reserve market, the quantity purchased both North and South of Path 15 was 500 MW for every hour of every day from June 1 to July 10. From July 15 to July 28, 250 MW was purchased for every hour in each zone. The quantity demanded of both spinning and non-spinning reserve fluctuates very little throughout the day, and the pattern of demand is very similar across days.

A third feature of these graphs, which we discuss in more detail below, is that the demand for regulation reserve is extremely variable across hours in the day and across days. On most days, the hourly demand more than doubles from it lowest value of the day to the highest value of the day in both congestion zones. During some days the peak demand is more than three times the value of the lowest demand for the day. Reasons offered by the ISO operations staff and market participants for this unexpectedly large demand for regulation reserve will be discussed later in this report.

The final feature common to these graphs is the volatility in bid sufficiencies for these markets across hours of the day. Although the average values of bid sufficiencies tend to increase across the three time periods for both North and South of Path 15, this is due primarily to the tremendous increase in the volatility of the bid sufficiencies across the

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discerning any movements in bid sufficiencies around the 100% value. For the same reason that we had to set the quantities of each ancillary service equal to zero on June 10 in Figures 3 and 4, in these Figures we set the values of bid sufficiency equal to zero for all hours and markets on June 10 because this information was missing from the data provided to us by the Market Surveillance Unit of the ISO.

three time periods. For example, in both North and South of Path 15, from June 1 to June 30, the maximum bid sufficiency never exceeded 800%. However, immediately following the extremely high prices in the Replacement Reserve market on July 9, bid sufficiencies far in excess of 1000% began to occur in this market, although periods when there were insufficient bids submitted to this market still occurred during the latter part of July. We now turn to the features of these plots that are unique to each time period.

3.2. June 1 to June 30: Prior to the Granting of Market-Based Rates

From the opening of the markets on March 30 up until the FERC order on June 30, the markets were characterized by chronic shortfalls of capacity offered and extensive dispatch of units under Reliability Must-Run (RMR) contracts. This is shown by the large number of hours that the bid sufficiency numbers were below 100% for this time period both North and South of Path 15. Because all firms bidding into these markets were under costs-based caps during most of this time period, the bid of the highest-priced unit dispatched in each hour was in the range of $5 to $10 per MW. It is important to remember that these are “market prices” in name only, because each firm was eligible to receive, at most, its cost-based bid-cap. For example, if this market price is $10 and the price cap of another unit is $8, then that unit is dispatched and paid its price-cap of $8, despite the fact that some suppliers may be receiving a price of $10 for their capacity. Because of software constraints, the ISO currently pays participants subject to a cost-based price-cap their bid price as opposed the price-cap so long as their bid price is below the market price for that hour.

On June 11, one newly divested unit became eligible (pending review and subject to refund) for a cost-based rate of $244.60/MW for ancillary services. The pattern of prices in Figure 1 reflects this change. Following this date, prices at or slightly below $244.60/MW frequently occurred both North and South of Path 15.

It is important to remember that the prices reported for these services do not accurately reflect the true per-unit average cost to the ISO of procuring its ancillary services needs. This is partly because a firm subject to cost-based rates that is supplying ancillary services receives only its cost-based rate, even if the market price is higher. Furthermore, there was considerable reliance by the ISO on units called under RMR contracts during this period. According to information provided to us by the Market Surveillance Unit of the ISO, some units can earn over $4,000/MW under their RMR contracts for providing these ancillary services, although the vast majority of RMR capacity has reliability payment rates less than $500/MW. Because of these very high reliability payment rates, RMR costs were sometimes considerable. The Market Surveillance Unit also reported that although payments to suppliers *through the auction market* are currently much higher than they were during the first three months of ISO operation, payments made *under RMR contracts* are now somewhat lower.

We have hoped to determine the relative cost of purchasing additional ancillary services capacity from RMR contracts versus the market, and how these two costs have changed over time as more firms obtain market-based rates and the price-cap on ancillary services has been changed from $500/MW to $250/MW. We were unable to obtain data from the ISO on the use of RMR units over any of our three time periods, and were therefore unable to perform this analysis. This is a very important direction for future study that we would like to pursue. This analysis will provide an estimate of the magnitude of the inefficiencies in the market for ancillary services caused by the existence of attractively priced (from the generator's perspective) RMR contracts that can be used to provide ancillary services if there are insufficient bids in the market to meet demand. This analysis will also provide valuable input into process used to determine the level of a damage control price cap on the prices of all ancillary services.

3.3. July 1 to July 13: Some Market-Based Rates but No ISO Price Cap

For the period July 1 to July 13, the ISO decided to procure ancillary services on a zonal basis for all hours and all days. Note that the CONGESTION indicator appears at the top of the price and quantity graphs for all hours during this time interval. Zonal purchase of ancillary services led to very low prices for all ancillary services and very little price volatility North of Path 15. However, South of Path 15, prices were extremely volatile and followed a pattern that has continued to this day.

During this time period, several new generator owners received FERC authorization to receive market-based rates for ancillary services. During this time interval both the $5000/MW and $9,999/MW prices in the replacement reserve market occurred. As a consequence, during the latter part of this time period, the ISO made dramatic changes in its demand for ancillary services across days and hours within the day. For example, for all hours of July 10, the ISO decided not to purchase any replacement reserve. This was followed by several days where the demand for ancillary services both North and South of Path 15 changed hour-by-hour within the day and across days.

Perhaps the most striking feature of this time period is the enormous increase in the variability of bid sufficiency within the day following ISO's decision to change its demand for replacement reserve. However, there were still several periods in the day when bid sufficiencies for replacement dipped below 100% despite extremely large bid sufficiencies during other hours of the day. It is important to note from Figures 3 and 4 that the demand for replacement reserve never exceeded 250 MW from July 11 to 13 in either zone, yet enormous within-day changes in bid sufficiencies occurred. The average value of hourly bid sufficiency in the other ancillary services also increased following July 10. This increase in the average value was due primarily to higher maximum daily values of hourly bid sufficiency, because the daily minimum of hourly bid sufficiency for all ancillary services were still very similar to the values before July 10.

3.4. July 14 to July 31: ISO Price Caps in Effect

During this time period the extreme price volatility in the zone South of Path 15 from July 1 to 13 spread to the zone North of Path 15. During this time period, the ISO purchased ancillary services on a zonal basis only when it anticipated inter-zonal congestion. The CONGESTION variable on these graphs denotes those hours. The price volatility in the zone South of Path 15 was greater than zone North of Path 15. There were many hours when the price of replacement reserve hit the initially imposed price cap of $500/MW and later the cap of $250/MW. (Recall that prices above $250/MW are plotted as $250/MW to preserve the resolution of the plot for prices below $50/MW.) With the exception of the last few days of July, the demands for spin, non-spin and replacement were relatively stable. The demand for regulation was very similar to what it was during the first half of July. Bid sufficiency, particularly for replacement reserve, increased substantially, although there were still a few hours when the number dipped below 100%. As noted earlier, values of bid sufficiency in excess of 1000% frequently occurred, particularly for the zone South of Path 15. (Recall that these values are displayed as 1000% in the Figure). Although average hourly bid sufficiency South of Path 15 appeared to increase for all ancillary services, for many hours during each day, the values are very close to 100% and for a smaller number significantly less than 100%. Values for hourly bid sufficiency slightly greater than 100% indicate that it is very likely that a single bidder can be pivotal in the market in the sense that if the firm's bid were excluded from the market there would be a insufficient bids to meet the ISO's needs.

For several hours during many days from June 11 to July 31, the capacity payment associated several ancillary services was far in excess of the real-time energy price. This occurred despite the fact that the former only requires the generator to be ready to produce, whereas the latter requires the generator to supply electricity. For example, on July 7 during hour 6, the price of spinning reserve capacity South of Path 15 was $240/MW, whereas the price of real-time energy during this same hour was $6.79/MWh. These numbers imply that a winning spinning reserve unit that was called on to produce energy in the real-time market received a total of $246.79 for each MW of capacity used during that hour. A firm that won in the supplemental energy market only received $6.79 per MW of capacity producing electricity during that hour.

3.5. Comparison with Power Exchange and Real Time Energy Markets

In this section we summarize the operation of the Power Exchange (PX) day-ahead energy market and the real-time energy market over our three time periods. As noted at the beginning of this section, in an ideal market for electrical energy, the expected variable profit that a generator could earn from bidding into the Power Exchange should equal the expected variable profit from participating in the ISO's ancillary services markets. The PX price less the generator's marginal cost is equal to the per unit variable profit from selling electricity into the PX.

Figure 9 plots the unconstrained PX prices and quantities over our three time periods. The first thing to notice when comparing PX prices to the ancillary services prices in Figures 1 and 2 is relatively small amount of price volatility in the PX price. During the entire month of June prices remain below $50/MWh and in the first two weeks of July, prices were below $100/MWh. Only during the latter part of July did prices approach $150, and only for three hours on July 27, when the price sequence $145.70, $151.10, and $150.71 occurred in Hours 15 through 17.

Another notable feature of the PX prices is the smooth pattern by which prices rise and fall during the day reflecting the changing pattern of electricity demand. In contrast to the ancillary services prices plots in Figures 1 and 2, there are no discrete jumps in prices across adjacent hours in the day from below $1 to more than $250 or from more than $250 back down below less than $1. Even for July 27, the day with the highest price PX in our sample, the PX prices smoothly climbed to their peak at $151.10 and then declined gradually. There were no jumps in prices across adjacent periods of more than $50, a very common occurrence for the ancillary prices in Figures 1 and 2, even for this very high-priced day. For example, the PX price began the day at $30.99 and smoothly rose to $48.00 in Hour 12 and $88.22 in Hour 14 on its way to the peak of $151.10 in Hour 16. The PX price smoothly fell to $32.80 by the end of the day. As is shown the third graph in Figure 9, the daily pattern of demand exactly mirrors the daily pattern of prices.

This clear relationship between increases in the demand and increases in the unconstrained price of electricity throughout the day and across days is consistent across all of the days from June 1 to July 31. This positive correlation between price and demand is consistent with a well-functioning market. As the market demands a greater quantity of electricity, generators must bring on line more expensive generating units to supply that demand, causing the market-clearing price to rise.

Comparing the pattern of PX quantities from June 1 to June 30 to the pattern of PX quantities from July 13 to July 31, we note that the range of demand throughout the day is higher for the period July 13 to July 31. The lowest value of demand for the day is slightly higher than it is for the period June 1 to June 30. The highest value of demand each day was around 35,000 MW in July. In June, this daily peak demand is significantly less than 30,000 MW. The range of PX prices throughout the day is greater for the period July 1 to July 31 than for June 1 to June 30. This is indicative of generator owners having to start the day with higher cost units operating in late July than in June and having to move up to even higher cost generating facilities to meet the much larger daily peak demand in late July versus June.

This same pattern of intra- and inter-day prices can be found in the real-time market as well as in the PX. Figure 10 plots the real-time energy price both North and South of Path 15 for our three time periods. There are only a few time periods (such as a few hours in the late evening on July 18) when there was congestion in real-time and was therefore a difference in the real-time prices between the two zones. Although real-time prices are more volatile both within and across days than the day ahead energy prices from the PX, the real-time prices do tend to move in the same direction as the PX prices both within and across days.

During the month of June, the average real-time energy price was low, reaching a maximum value less than $100/MWh. The volatility of prices during this time period is significantly less than that for the other two time periods. This is consistent with the view that there was significantly more low-priced capacity available to supply electricity at very short notice in the supplemental energy market during June than in early and late July, when PX demand was higher than in June. Comparing the level of PX demand at the same time of day across the three time periods, we note that the average value of PX demand in a given hour of the day in June is less than that value of demand for July 1 to July 13. The average PX demand for that hour in July 1 to July 13 is less than the analogous value of demand for July 13 to July 31. Consequently, this greater necessity of using higher cost capacity throughout the day in is reflected in higher average real-time prices and significantly more price variability throughout the day. Despite the increased volatility of these real-time prices relative to the PX day-ahead prices across all three time periods, there are many real-time energy prices in the lowest two price ranges given in Figures 7 and 8. The ranges $150 to $250 and greater than or equal to $250, are only hit during the time period July 13 to July 31, and for only a few hours. Price movements across adjacent hours tend to be a little less smooth than in the PX, but we do not see the dramatic jumps in prices across adjacent hours in the day that occur in the ancillary services prices shown in Figures 1 and 2.

Matching up the time scale of the PX prices and real-time prices, we also see that in periods within the day when prices are higher in the PX, prices also tend to be higher in the real-time market. This is consistent with the view that generators expect to earn the same amount of variable profit from bidding into the PX and the supplemental energy market.

For comparison, in Figure 11 we plot the market-clearing price and the demand for replacement reserve south of Path 15 for our three time periods. These are the analogous graphs to Figure 9 for the replacement reserve market. Following our usual convention, we plot any price above $250/MW as $250/MW to best reveal price movements in the $0 to $50 range. In these plots we see few of the patterns that are present in the PX market. For example, in the final two plots, demand is constant across all hours in the day, yet the range of prices during the day is from $0.01 to $9,999. The highest price of $9,999 occurred in several periods when demand was 250MW, whereas the price of $5,000 occurred on another day when demand was twice as large.

These replacement reserve market results contradict the usual increasing relationship between market demand and the cost of supplying larger quantities of output. Only during the period from June 1 to June 30, when no firms had market-based rates for replacement reserve, was there a pattern of prices and quantities that is not grossly inconsistent with the pattern of PX prices and quantities. During this period there was very little price volatility and a constant demand.[14]

3.6. Bidding Behavior by Owners of Generating Capacity

To understand the causes of the time series behavior of the prices for ancillary services given in Figures 1 and 2, we performed a preliminary analysis of the bidding behavior of the investor-owned utilities (IOUs)—PG&E, SCE and SDGE—and the new generator owners (NGOs)—AES Corporation, Duke Energy, Dynergy and Houston Industries—for our three time periods. In particular, we investigated the extent to which generators withheld generating capacity from both the day-ahead energy market and the ancillary services market in order to be called on under their Reliability Must-Run contracts.[15]

Figure 12 plots the total hourly bids for each ancillary service by all of the IOUs statewide for each of our three time periods.[16] Comparing the plots for each ancillary service across the three time periods, a uniform increase in the average amount of capacity bid into each of these markets across the three time periods can be detected. This increase in the average amount bid is particularly easy to see for the replacement reserve market. For the period June 1 to June 30, the maximum amount bid was around 3,000 MW, whereas for the period July 1 to July 13, the maximum bid into the replacement reserve market rose to over 5,000 MW. On July 9, the maximum amount bid was over 10,000 MW. For the period, July 13 to July 31, the maximum amount bid ranges from 7,000 MW to 9,000 MW. The other ancillary services follow this same pattern of increased bid quantities over time, although the shift is far less pronounced.

Another striking feature of these graphs is the large variability throughout the day in the amount bid into these ancillary services markets, particularly the replacement reserve market. Variability in bids should be contrasted with the fact, shown in Figures 3 and 4, that the demand for this service is the same for all hours of the day during the period June 1 to July 10. Part of the reason for this volatility is the cumulative nature of bids submitted to the ancillary services markets, although generators do have the option to submit very small or even zero bids to the replacement market even if they submit large

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[14] Recall that because of missing values of demand for June 6, we plot the value of demand as zero for all hours of the day.

[15] This analysis relies on bidding and scheduled energy data provided to us by the Market Surveillance Unit. Because we received this bidding and energy schedule data very recently, we were unable to perform a more comprehensive analysis. Our results should therefore be considered preliminary. Further analysis and extensions are planned.

[16] Once again the bids for all ancillary services for June 10 were missing from the data provided to us, so the values for all hours on this day were plotted as zero.

bids to the regulation, spin, and non-spin markets. The fact that the IOUs do just that is clear from the tremendous range of total replacement reserve bids by the IOUs throughout the day in each of the plots. In addition, the fact that the total IOU quantity bid into a lower quality market often falls below the total IOU quantity bid into a higher quality market, indicates that many generators submit bids which reduce the total capacity bid for lower quality services. Later in this report, we will argue that it is precisely this flexibility in bidding capacity into the ancillary services that contributes to the tremendous volatility in ancillary services prices.

A different story of bidding behavior emerges for the New Generator Owners (NGOs), particularly during the time period July 1 to July 13. Figure 13 plots the statewide total of ancillary services bids by hour by the four NGOs for our three time periods. During the month of June the amount bid into the replacement reserve market by the NGOs showed considerably less fluctuations within the day than the amount bid into the replacement reserve market by the IOUs. For the latter part of June there was very little fluctuation in the amount bid into the replacement reserve market.[17] Recall that no firms were allowed to receive market-based prices during this time period. During the period July 1 to July 13, NGO bids for all ancillary services were very stable throughout the day. The pattern of NGO bids into the replacement reserve market is particularly notable in this regard, hovering around 1000 MW until July 8 when it fell to close to 500 MW. Looking at the time path of replacement reserve prices South of Path 15 as shown in the second graph in Figure 11, we see that this reduction in capacity bid by the NGO on July 8 exactly coincides with a continuous period of prices close to $250/MW. Looking at the second graph on Figure 11, we see that the amount of statewide replacement capacity bids submitted by the IOUs dipped to very low levels during this same time period. The events on July 9 can also be viewed from the perspective of Figures 12 and 13. For the both the IOUs and NGOs, the total amount bid in the early hours of July 9 was higher than average for this time period. However, for both the IOUs and NGOs the amount of capacity bid into this market in the later hours of the day was close to the lowest amount bid in during any hour in the period July 1 to July 13. Turning to the second graph, on Figure 11, we see a the spike in the replacement reserve price South of Path 15 of $5,000 for several hours during the time period in which the amount bid by both the IOUs and NGOs into the replacement reserve market was very small.

To investigate impact of capacity withholding from the replacement reserve market on prices in the replacement reserve market in greater detail, in Figure 14 we plot the total hourly bids of IOU capacity South of Path 15 into the replacement reserve market for the period July 13 to July 31. The second graph plots to total hourly bids of NGO capacity south of Path 15 into the replacement reserve market for this same time period. Superimposed on each graph is a plot of hourly prices South of Path 15 for replacement reserves. For almost all hours when this price hit the price-cap in force during that hour,

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[17] Once again, because of missing data for June 10, we plotted the total bids for all hours by the NGOs as zero.

$500/MW or $250/MW, there was a simultaneous trough in the total hourly amount bid by both the IOUs and NGOs into the replacement reserve market. Prices in the replacement reserve market South of Path 15 hit the price cap when both the IOUs and NGOs simultaneously bid less capacity into that market. Turning to the last graph on Figure 6 and comparing it to the hours of very high prices in Figure 14, we see that some of the periods of high prices in Figure 14 are characterized by bid insufficiencies. However, this is not the case for many of the high-priced periods in Figure 14, particularly for the time period in which the $250/MW cap was in effect.

4. Structural Deficiencies in the Ancillary Service Markets

As mentioned above, it appears that the markets for ancillary services have not been functioning as competitively as the ones for electrical energy. As the starting point for an analysis of these markets, it is therefore worthwhile to consider the factors that make the markets for ancillary services distinct from those for energy. Once we have identified the potential structural problems with the ancillary services markets, we can try to assess the *long term* impact that these barriers are likely to have on the performance of these markets. In doing so, we can begin to distinguish between transitional problems and problems that are likely to persist.

We have identified nine major factors that have limited competition in these markets relative to energy markets:

1. Some suppliers can receive market-based rates, while others are subject to cost-based rate caps.

2. The demand for ancillary services has been far higher than anticipated.

3. The demand for each ancillary service does not depend on its market-clearing price, and the ISO has limited ability to substitute between services in procuring its system reliability capacity needs.

4. Reliability Must-Run contracts create perverse incentives for bidding into the ancillary services markets.

5. Ancillary services have been purchased on a zonal basis.

6. Dispatch and settlement practices for the provision of imbalance energy are ambiguous.

7. The allocation of ancillary service costs among scheduling coordinators has been flawed.

8. Suppliers from outside of the ISO control area were excluded from the provision of ancillary services.

9. Limitations of the ISO's software have exacerbated these problems.

In the following subsections, we describe each of these contributing factors in more detail. While we are confident that each of these factors has contributed to the current market difficulties, the relative significance of each factor is difficult to determine, and has surely changed over time. Additional analysis of market data currently underway by the Committee will provide further information about the absolute and relative magnitude of these various factors. The Committee believes that this quantitative analysis is necessary before we can offer more definitive conclusions and recommendations for changes in the market design. Nevertheless, we believe that it is desirable to move promptly to correct all of the problems that can be corrected without more definitive study as soon as possible. Recommendations based on our current analysis are given later in this report.

4.1. Asymmetric Regulation of Suppliers

Since their inception in March, the ancillary services markets have never functioned in the manner that was originally envisioned by its designers. Our understanding of the original market design is that it intended that a market process provide price discovery for each reserve product, as well as for energy. However, FERC never granted the incumbent investor-owned utilities (Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDGE)) permission to earn market-based rates for the provision of ancillary services. Instead, each IOU has operated under a cost-based cap on the prices that it can earn in these markets.

In its first three months of operation, the ISO experienced a chronic shortfall of capacity bid into its ancillary service markets (see below) and consistently was forced to call upon units under the terms of reliability must-run (RMR) contracts to provide ancillary services. This was apparently due to the fact that most generators in the market could earn *more* revenue under the terms of their RMR contracts than they could earn under their FERC cost-based price caps. This problem persists, even in the replacement reserve market, because several units receive RMR rates far in excess of the current ISO price caps for these services (see Section 4.4 below).

With the divestiture of much of the gas-fired capacity of both PG&E and SCE, many of the generation units currently eligible to supply ancillary services are now owned by firms that are not covered under the same cost-based rates as the IOUs. In a series of filings to FERC, each of the new owners of this capacity has requested permission to earn market-based rates on the sale of ancillary services.[18] Beginning with its June 30 order, FERC has accepted most of these filings and additionally ruled that replacement reserve was not an ancillary service. This meant that replacement reserve was in fact *never* covered under the cost-based caps. The generation capacity of the major firms in the ancillary services market is given in Table 3.[19]

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[18] See FERC Docket No. ER98-2843-001, ER98-2844-001, ER98-2883-001, ER98-2971-001, ER98-2972-001, and ER98-2977-001.

[19] These figures are drawn from the ISO Generator Master File, which is derived from figures given by the generators to the ISO. We note that there are considerable discrepancies between some of the capacities given below and those reported elsewhere. We encourage stakeholders to work with the ISO to clarify unit capabilities.

Resources	Nameplate Capacity*	10 min AGC Capacity****	30 min AGC Capacity	10 Min Ramp Capacity	60 min Ramp Capacity
Market Based Rates					
AES	3756	461	1382	770	2988
DST	1584	204	612	684	1584
HI	2737	446	1338	684	2555
DETM**	2639	260	780	425	1691
Cost-based Caps					
CDWR	2090	0	0	1621	2042
PG&E***	21607	2527	3649	7538	9913
SCE	12037	180	540	2079	2786
SDG&E	2560	305	915	700	2119
Totals	49650	4511	9600	14629	26318

*Includes QF capacity. Must-take QF and nuclear capacity are not included in the other columns.
**Duke Energy has filed for market-based rates but the request has not yet been granted by FERC.
***Includes PG&E Utility Electric Supply and PG&E Power Generation.
****Rampable capacity figures include hydro capacity. The amount of hydro capacity available for provision of ancillary services at times can be significantly reduced by minimum flow constraints on the hydro systems.

Table 3: Generation and Ancillary Service Capabilities by Firm

Under the current regulatory situation, nearly half of the ancillary-services capacity in the ISO control area is either eligible for, or has applied for, market-based rates, while the majority of the capacity remains under a cost-based cap for the supply of regulation, spinning, and non-spinning reserves. Much of the capacity that is *physically* able to supply ancillary services, therefore has little *economic* incentive to do so. Normally, a market will self-correct to high prices by attracting additional supply, thereby lowering the price. Because of the cost-based price caps, however, many of the sellers in this market can earn no more revenue by selling into this market when market prices are high than when they are low.

The transition from one regulatory regime to another has further restricted supply. On July 1, Duke Energy took possession of 3 generation facilities, but has not yet received permission to earn market-based rates on regulation, spinning and non-spinning reserves. Pending the FERC decision on this application, Duke states that it is unable to bid these units into the ancillary service markets. According to the capacity figures provided to us by the ISO, Duke Energy owns more than 2,500 MW of capacity that it claims it is not able to bid into these markets. This lack of participation of Duke Energy units has exacerbated the supply shortfall for ancillary services in both North and South on Path 15 at exactly the same time other units became eligible for market-based rates for these services.

The IOUs do have some incentive to provide additional capacity to the ancillary service markets when prices are high despite being subject to cost-based caps on their supply of these services. This is because they are large *consumers* of ancillary services. PG&E and SCE are by far the largest purchasers in the PX, and are therefore by far the largest buyers of ancillary services procured through the ISO's daily auctions. These firms therefore have an incentive to defensively bid capacity into these markets in order to lower the price that they have to pay as consumers.

Such defensive bidding may have been discouraged by limited information about ancillary services costs. The presence of cost-based caps on many market participants and the uncertain number of RMR contracts that will be called on to provide ancillary services in any hour make it difficult for market participants to forecast total ancillary services costs for any hour. Even if electricity suppliers knew the market-clearing price for each ancillary service, they would still have a very difficult time forecasting their ancillary services costs for a given hour because the firms do not know what fraction of the total capacity sold in this market was paid the market-clearing price and what fraction was paid according to cost-based caps. In addition, these firms also do not know how many RMR plants will be called and the average RMR price paid. For all of these reasons, ancillary services costs have been are difficult to predict. In addition, the fact that transmission line owners pay for ancillary services procured under RMR contracts, whereas SCs pay for ancillary services provided by these markets, may further dull the incentives the IOUs have for defensive bidding.

The three plots of the time series of total hourly bids submitted by the IOUs for each ancillary services given in Figure 12 is consistent with this defensive bidding strategy. The average amount of IOU capacity bid each hour into all of the ancillary services markets is less in period June 1 to June 30, when all firms received cost-based caps, than that in the period July 14 to July 31, when several NGOs had the authority to receive market-based prices.

A major determinant of the thinness of the regulation, spin, and non-spinning reserve markets is the existence of cost-based caps on the bid prices of the IOUs. Besides the incentives for defensive bidding described above, these firms have little financial incentive to offer additional capacity to these markets when they expect high market prices. The thinness of the replacement market is more puzzling because all generators are eligible for market-based rates. For this market, we believe that the combination of the RMR contracts the current ISO bidding protocol and market-clearing process helps bidders set extremely high prices during certain hours.

The logic for this view is as follows. During the high demand periods within certain days, generators with RMR contracts know with virtual certainty that they will be called under their RMR contracts and receive their RMR payment. Under these circumstances a generator bidding into the ancillary services market will rationally bid significantly more than its RMR payment rate, because the generator knows that if it does not win in the ancillary services market, it will be paid its RMR payment with virtual certainty. Because a profit maximizing generator will bid into the market to achieve the same level of expected variable profit that it can obtain under its RMR contract, its bid price will be significantly above its RMR payment to reflect that generator's assessment of a lower probability of winning in the ancillary services market. Now if other generators are aware that this generator faces this very high probability of being called under its RMR contract, the other firms know that this generator has a very strong incentive to bid a high price into the market. Therefore, regardless of the RMR price these firms face, they also have an incentive to bid a higher price. because they expect the firms with high RMR payments rate to bid a high price. of the expected high priced bid by the firm that knows with virtual certainty it will called under its RMR contract because of conditions in the day-ahead energy market or other information. During these hours, the RMR contracts allow generators bidding into the replacement reserve market to buy a lottery ticket with virtually no risk of losing money, because the RMR contract provides insurance against not receiving revenues in that hour provided by the RMR contract.

4.2. Demand for Ancillary Services is Higher than Anticipated

Many of the other factors listed in this section have contributed to a reduction in the available *supply* of ancillary services. These reductions in supply would have caused fewer problems if the *demand* for ancillary services had not been so much higher than anticipated. There appears to be a consensus that the ISO is acquiring significantly higher levels of ancillary reserves than that reflected in pre-ISO historical norms.

WSCC standards for operational reserves are about 6.5% of system load for spin and non-spin combined.[20] The WSCC leaves the level of regulation reserve largely to the discretion of the operator, but this level has historically been about 3% of load. There is no WSCC standard for replacement reserve, but operators have traditionally kept one hour reserves on hand to replace operating reserves in the event of a serious contingency. A comparison of WSCC standard, or historical, quantities for these three reserve products with the actual quantities of regulation, spin and non-spin purchased by the ISO (Table 4) shows that the ISO often requires more than twice the amount of these services than has historically been the case.[21]

[20] The WSCC requires spinning and non-spinning reserves total 5% of hydro and 7% of non-hydro generation output.

[21] Scheduled generation here refers to the total energy scheduled by generation *within* the ISO control area. This is an approximation of the actual schedule for which the ISO must acquire services.

	June				July			
	hours 1-6	Hours 7-12	hours 13-18	hours 19-24	Hours 1-6	Hours 7-12	hours 13-18	hours 19-24
Avg. scheduled generation (excludes imports)	16356	19304	20913	19369	17624	22978	28160	24340
3% of scheduled load	491	579	627	581	529	689	845	730
Avg. regulation required	1368	1675	1281	1776	1674	2131	1828	2447
7% of scheduled load	1145	1351	1464	1356	1234	1608	1971	1704
Avg. spin and non-spin required	1204	1428	1510	1424	1726	1850	2037	1915
Avg. total ancillary services required	3572	4103	3791	4200	4021	4621	4616	5043

Table 4: Ancillary Service Purchases During June and July 1998

Table 4 reveals that regulation accounts for most of the unexpected increase in ancillary service purchases. This is especially true during the shoulder periods (hours 7-12 and 19-24) when both generation and load quantities change rapidly. ISO operators state that a one factor behind the need for increased regulation capacity is the current ISO protocol for moving up the real-time energy bid stack. It is our understanding that, at any point in time, the operator must decide whether to move up or down the real-time energy bid stack or simply use more regulation capacity to meet unexpected fluctuations in electricity demand relative to its schedule. The current ISO protocol requires that sufficiently large amount of upward or downward system-wide regulation capacity be in use before a decision is made to move up or down in the real-time energy bid stack. The operator often does not know, with sufficient certainty on a day-ahead basis, if this movement will be in the upward or downward direction. Consequently, the ISO must procure an increased amount regulation capacity. Another potential cause of the increased demand for regulation is that generating schedules take the form of discrete hourly steps. Generators must pay for any deviations from these step function schedules at the real-time hourly imbalance price. During these shoulder periods the level of imbalances can be extreme due to the sharp increases in consumption and output that are necessary to reach the next hourly scheduled "step" for each unit a generator owns. A final potential reason for this increased demand for regulation by the ISO has to do with how it pays for instructed versus uninstructed deviations. As discussed earlier, uninstructed deviations are settled at the average of the six 10-minute prices for each hour. Instructed deviations from schedule are settled at the 10-minute price relevant when the instruction is given to the generator by the ISO. This asymmetry in prices at which different types of deviations from schedules are settled can create incentives for uninstructed over-generation during high-priced 10-minute periods and uninstructed under-generation during low-priced 10-minute periods. We would like to determine if any of these three potential reasons for an increased demand for regulation capacity is actually relevant. If any one is relevant, we would like to quantify how much larger it makes the demand for regulation.

The ISO's purchase of regulation capacity at levels that by itself sometimes exceed the WSCC requirements for *all* ancillary services has not been offset by a decreased purchases of any other ancillary services. The ISO has continued to purchase spin and non-spin at a level *over* 7% of load. Even within the two spinning reserve services, the current practice, as described below, is *not* to buy more of one service and less of the other when one is considerably cheaper.

Many aspects of the market design have conspired to create an increased need for reserves. As the above discussion makes clear, the task of acquiring ancillary services is much more complicated for a third party in the context of a competitive market than it was for vertically integrated utilities. Particularly within the context of the California market design, generators are allowed to deviate from their schedules in real-time for both economic and non-economic reasons, yet the ISO must still maintain system reliability. It is hard to see how, under this market design, the ISO can purchase less ancillary services capacity than was procured when the grid was centrally dispatched by a single IOU and certain units were used to provide a load-following service, a product not available in the current market design. However, the optimal quantity of regulation or any other ancillary services capacity to purchase in this environment is unknown. We note, as well, that the ISO does not bear the final cost of the reserves that it acquires. These are passed on to the users of the system. However, as a fledgling institution, the ISO has a very strong incentive to avoid serious reliability problems. The thorny problem of providing operators the incentive to both minimize costs and ensure adequate reliability is a long-standing one in the electricity industry.

4.3. Ancillary Services Are Not Procured Rationally

While the *amount* of ancillary services that the ISO has procured has been a source of the high prices seen today, the *manner* in which these services are procured is also a major contributing factor. The ISO has been purchasing most services according to a rigid standard, not allowing for any substitution between services within that standard. The quality of ancillary services can, with some qualifications, be characterized as hierarchical, with regulation being the highest quality product, followed by spin, non-spin, and lastly, replacement reserve. One would not expect a rational buyer of ancillary services to purchase a lower quality ancillary service at a given price if a higher quality service is available at a lower price. However, it has usually been the case that the market-clearing prices for "inferior" ancillary services such as spinning reserve have exceeded those for "superior" services such as regulation. There are many cases in which the difference between these inverted prices have been extreme (see Table 5). Although this inflexible purchasing practice can be viewed as consistent with the ISO tariff, it is our understanding, based on discussions with ISO consultants and staff, that it is *not* consistent with earlier versions of the market design. It was intended that the ISO be given some flexibility to act as a "rational" buyer of ancillary services.[22] In addition, Section 2.5.8 of the ISO tariff contains the following two sentences: "The ISO shall operate a competitive Day-Ahead and Hour-Ahead market to procure Ancillary Services. It shall purchase Ancillary Services capacity at least cost to End-Use Customers consistent with maintaining system reliability."

Month	**June**		**July**	
	SP15	**NP15**	**SP15**	**NP15**
Hours when at least one inferior service had a higher price than a superior service	90%	83%	73%	91%
Hours when at least one inferior service had a price more than $50 greater than a superior service	10%	8%	30%	7%

Table 5: Frequency of "Inverted" Prices

Under the implementation of the market, all the bidders *know* that the ISO operators will adhere to rigid procedures when acquiring ancillary services. Therefore, the bidders know with relative certainty exactly how much of each service the ISO will need to acquire. In addition, the participants know that the ISO's demand for each service does not in general depend on the market-clearing price. This knowledge, combined with detailed familiarity about the supply conditions in the market, all too often has allowed firms to accurately predict exactly when their capacity *must* be purchased by the ISO. In other words, firms know when their capacity is pivotal to the market. Under these conditions, the ISO must accept the capacity offered by these firms at any price (subject to price caps). Thus, current purchasing practices have produced a very predictable and inflexible demand for ancillary services. This is hardly "the market" in operation. In a true

[22] See "Response of the California Independent System Operator Corp. and the California Power Exchange Corp. to Request for Additional Information." FERC Docket Nos. ER96-1663-003 and EC96-19-003. May 20, 1997. In particular Attachment IV, "Priority Pricing of Ancillary Services," by Robert Wilson.

free market setting, buyers would substitute services, negotiate contractual protections, and encourage other suppliers to step forward; and bidders would not be subject to cost-based rate caps.

4.4. Perverse Incentives Created by Reliability Must-Run Contracts

Reliability must-run (RMR) contracts were designed to provide a means for correcting for the locational market power of certain generation resources. Such generation, if purchased under market protocols that required power to be purchased from the zone in which it is needed, could demand a considerable premium over marginal cost since there is often no viable substitute for that generation short of curtailing load. In order to avoid the abuse of such market power, RMR contracts were created for the bulk of the gas-fired generation capacity located within California. RMRs were originally envisioned as "call" contracts to which the ISO could turn to procure generation from certain resources at a pre-negotiated and, in theory, cost-based price.[23] This concept was argued to be a satisfactory means of mitigating local market power, provided that there was no market power in the *overall* (non-local) market.

In practice, the market has been negatively impacted by RMR contracts through both the overuse of some contracts and the underuse of others. It could be argued that, given current price caps, the ISO may have been better off with *no* RMR contracts than it is with the contracts in their current form. As mentioned above, several contracts specify extremely high availability payments, sometimes in excess of $4000. The owner of such units can collect the most revenue for these resources by having the RMR contracts on these units invoked as much as possible. These expensive units therefore have little incentive to bid into the market at times when there is a reasonable probability that they may be called upon under RMRs. This is especially true for units subject to either FERC or ISO imposed price caps. If there were little or no chance that a given unit will be called upon under its RMR contract, the unit's owner loses little by bidding the unit into the market. However, the times at which these units are most likely to be called upon under its RMR contract are exactly the times when they are most needed in the market--high demand hours. This was widely acknowledged to be a significant problem during the earliest months of market operation. The problem has now been offset somewhat by the fact that market-based rates have of late been extremely high. As discussed earlier, we would like to evaluate the severity of this effect under the current market conditions.

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[23] See Section VII of Joskow, P., Frame, R., Jurewitz, J., Walther, R., and Hieronymous, W. (1996), "Report on Horizontal Market Power Issues", Supplement of the Southern California Edison Company and the San Diego Gas & Electric Company to Application for Authority to Sell Electric Energy at Market-Based Rates Using a Power Exchange. Federal Energy Regulatory Commission, Docket No. ER96-1663-000. See also Jurewitz and Walther. "Must-run generation: can we mix regulation and competition successfully?" *The Electricity Journal*, 10(10): 44-55.

This problem is exacerbated by the extremely high level of some of the pre-set payments. The RMR rates were meant to include recovery of some fixed costs, in addition to the marginal cost of operation. However, the rate of fixed cost recovery was determined by dividing the total annual fixed cost by the expected number of hours under which the unit would be called under an RMR. In fact most units have been called upon to provide generation under RMR contracts far more frequently than had been forecast when those rates were negotiated. This means that some units can recover far more than their total annual fixed costs through RMR payments.[24] Later in this report we make recommendations for modifications of the RMR contracts that help to alleviate these reduced incentives for participation in the market caused by this RMR payment scheme.

Figure 15 contains a plot of the capacity under RMR contracts as a function of their payment if they are called to produce electricity under the terms of their RMR contract. This payment is the sum of the Reliability Payment Rate plus the fuel cost, operating and maintenance cost and emission cost per MWh. This graph also plots the estimated marginal cost curve for generation from these RMR units.[25] Because there are several RMR contracts with payments in excess of $4000/MWH, we have truncated the graph at a payment rate of $1000/MWH to illustrate the divergence between marginal generation cost of the supply curve for RMR energy. Extending the graph to $4500 yields approximately 500 MW more in RMR capacity, resulting in a total of over 14,000 MW of statewide RMR capacity. Given this RMR capacity figure, if the ISO were able to call on RMR units for both economic and reliability reasons it would have a ready source of additional supply during those periods when the demand for ancillary services is high. This large source of supply at known prices would discipline any attempts by generators to exercise market power by bidding high prices into the ancillary services markets.

Capacity withholding and RMR payments

We were able to perform a preliminary analysis of the extent of capacity withholding in this market. For each hour and each generating unit we computed the following two indicator variables. The first indicator variable was set equal to one if the unit was scheduled to provide a non-zero amount of energy. The second indicator variable determined whether a unit submitted a bid beyond the “RMR placeholder bid”

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[24] Under the current Type A RMR contracts, which all generators started the market with, the “availability’ payment, the mechanism for recovery of fixed costs, is paid each time the generator is called under the RMR contract. The current Type B RMR contract pays the generator’s entire fixed cost up front, but imposes significant penalties on the generator for any market revenues it earns in excess of its annual total costs. If the ISO calls the unit more times than specified in the contract, it pays a “pre-negotiated’ penalty variable cost rate. We understand from the ISO that, under the initial contracts, these rates are significantly greater than the unit’s contractual variable cost to compensate for the increased wear and tear from these additional hours.

[25] The estimates of marginal cost include fuel cost and variable O&M. These estimates are taken from Borenstein, S. and J. Bushnell, “An Empirical Analysis of the Potential for Market Power in California’s Electricity Industry,” University of California Energy Institute. PWP-044, May 1998.

level to any of the ancillary services market during that same hour.[26]

The two hourly generating-unit-level indicator variables where combined into a single market participation indicator variable as follows. If either the scheduled energy indicator variable or the ancillary services market indicator variable was equal to one, we set the market participation variable equal to one. Using this procedure, we computed this market participation variable for each generating unit in the ISO's Participant Master File for each hour from June 1 to July 31. We then computed the fraction of total hours in each of our three time periods that the value of this market participation indicator variable was equal to one for each generating unit. For most of the generating units this fraction was equal to or very close to one. However, for a number of units the value of this fraction was very small for the three time periods, and even equal to zero for some time periods. On further investigation, we found that the vast majority of these units with small values of this market-participation fraction had RMR contracts in force.

There also appeared to be an inverse relationship between the value of the RMR payment and the value of this market-participation fraction. To investigate this hypothesis more rigorously, we obtained the reliability must run payment level for each generating unit from the Market Surveillance Unit of the ISO. For each of our time periods, we then regressed the value of an RMR unit's market participation fraction on the value of its RMR payment level. For the first two time periods we did not find any statistically significant correlation between the level of the RMR payment and the market participation fraction for that unit. However, for the third time period, from July 13 to July 31, we found a statistically significant negative correlation between the level of the RMR payment and that unit's market participation fraction.

Although they are far from definitive, our regression results suggest that units with particularly high RMR payment rates are less likely to either have day-ahead energy scheduled or bid into any of the ancillary services markets (beyond the placeholder bid level). We should also caution that our results are still preliminary, as well as conditional on the accuracy of the RMR payment data, energy schedule data, and ancillary services bid data made available to us for analysis. With this caveat, our results suggest that high RMR payment rates undermine the incentives for a generating unit to participate in the day-ahead energy markets and/or the ancillary services markets.

[26] From our conversations with staff at the Market Surveillance Unit we were told that generators wishing to be called to provide ancillary services under their Reliability Must Run contracts were asked to submit very small non-zero "placeholder bids" on the order of 0.0x MW, where x is some number between 1 and 9. Consequently, in constructing our indicator variable for whether or not a unit bid into the ancillary services market we set this indicator value equal to one only if the unit bid above this placeholder level into any one of the four ancillary services markets. Consequently, all units that submitted these "placeholder bids" for all four markets were given a value of zero for this indicator variable.

RMRs and the mitigation of local market power

The second difficulty with the current implementation of RMR contracts is that the protocols allow firms to continue to exercise market power.[27] If these contracts were truly "call" options with a pre-negotiated strike price, the ISO would be able to purchase ancillary service capacity at this price whenever the market price rose higher than the contract price. The current practice, however, is to call upon RMR units only when those same units cannot be acquired, at any (non-capped) price, from a "market." Currently, some of these units are successfully bidding "market" rates far in excess of their RMR rates, and thus presumably far in excess of the (long run) marginal costs upon which the RMR rates were based. These contracts therefore seldom mitigate market power. Instead, the usual result under the current implementation of RMR contracts is that the ISO gets to purchase under the RMR rate only when that rate far exceeds what would otherwise be the market clearing price.[28]

As mentioned above, some units have been able to earn market prices far in excess of the RMR rates. This may in part be due to the fact that the market through which their capacity is acquired is small enough that these units enjoy some market power. When the market is defined over a smaller region, such as southern California, the number of competitors is reduced and extremely high bids, such as $5000, can still be successful. In a broader market, such a unit might be outside of the set of successful bids and therefore have to be called under RMR. The PX, for example, does not hold a separate auction for energy in San Francisco where a single unit can be pivotal, bid any price, and be considered "in" the market. Ancillary services, however, are sometimes purchased on a zonal basis (see the subsection immediately below) and some firms likely have market power over the southern zone. These firms can therefore exercise their market power in this zone, have their capacity selected at high prices, and avoid being called under an RMR.

4.5. Zonal Purchase of Ancillary Services

An additional limitation on the competitiveness of the ancillary service markets has been the division of the state-wide market into smaller sub-regions. The ISO tariff

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[27] A third potential difficulty with RMRs, as they are currently constituted, is the potential incentive problems that may arise from the interaction of units with "A' and "B' type contracts. We do not have enough information at this time to evaluate this problem, but would like to monitor its potential impact on the market.

[28] Some market participants would clearly prefer that the ISO be forced to accept high bids before turning to RMR units, arguing that the "market" should be used before RMR units are called. However, this view rests on an artificially narrow notion of the "market." Buyers with urgent and inelastic needs rarely rely entirely on a spot market for their needs; a true "market" includes a variety of contractual forms, from spot markets to long-term contracts to vertical integration.

Section 2.5.4 states that "For each of the Ancillary Services, the ISO shall determine the required locational dispersion in accordance with ISO Controlled Grid reliability requirement." This tariff provision itself is a potential problem when there is market power within a given zone. We address this point below. In addition, the ISO has on occasion purchased ancillary services on a zonal basis, even when the transmission path connecting the northern and southern zone has *not* been congested. This has been done either out of concern over the *potential* for congestion on Path 15, or because congestion on other paths within the ISO control area has limited the ISO's ability to "transport" ancillary services within its control area. For example, a 1000 MW statewide need for replacement reserve might, absent congestion, be provided from 800 MW of generation in the North and 200 MW of capacity in the South. If, in this example there were congestion, or a forecast of congestion, the ISO would instead purchase 500 MW of replacement capacity in the North and 500 MW in the South. If supply is tight in the southern zone, the remaining suppliers may enjoy local (or zonal) market power. As noted above, this split purchase is sometimes done even when there is no congestion on Path 15. Thus, on occasion, the ISO's ancillary service prices have varied significantly by zone, even when the imbalance energy price has been the same for each zone.[29] In short, even if the ancillary service markets can be made workably competitive on a state-wide basis, they may remain vulnerable to market power when conducted on a zonal basis. We propose an alternative state-wide auction later in the report.

4.6. Ambiguous Dispatch Practices for the Provision of Imbalance Energy

As described in Section 2, the market design implied by the ISO tariff indicates that suppliers of *all* ancillary services are also eligible to earn the imbalance energy price if they are called upon to supply energy in addition to reserve potential. Bidders into the PX and these markets were expected to weigh potential earnings from both capacity and imbalance energy sales in making their decision about which market to participate in.

However, it is virtually impossible for suppliers of regulation reserve to set or earn the imbalance energy price due to the fact that their output levels are constantly increasing and decreasing, creating a net imbalance that is often near zero for the hour. A supplier of regulation energy is frequently required to vary its output both upwards and downwards. Imbalance payments, however, are based upon the *net* imbalance during a given time period.[30] Thus for a provider of regulation energy, the net imbalance usually far understates the true contribution that the generator is making to the system.

[29] The ISO is also currently not able to utilize transmission capacity for ancillary services, even when it might be economic to do so. Because of this, transmission capacity is sometimes allocated to ship energy between zones with very small energy price differences, while these same zones may at the same time experience major ancillary service price differences.

[30] The software that tracks these imbalances calculates them every 10 minutes while a generator providing regulation may be revising output far more frequently.

This problem contributed to the shortage of capacity bid into the regulation market during the early months of its operation. On May 21, the ISO instituted the REPA mechanism to pay suppliers of regulation energy an amount based upon the total (up and down) adjustable capacity they provide during an hour. Bid sufficiency in the regulation market has improved since the implementation of the REPA payments, but still remains below 100% in many hours.

Suppliers of other ancillary services have not always been dispatched for the provision of imbalance energy, even when they have the lowest available energy bid. At times, ISO operators have judged that the reserve potential provided through these ancillary services should not be reduced by calling upon these units to provide energy. This usually occurs during high demand periods in which concerns about sufficient operating reserves are the highest. ISO operators have indicated that this practice is consistent with the original spirit of the technical design of the ancillary services markets and is necessary for compliance with WSCC reserve standards. While this practice may be the most prudent one from a reliability standpoint, the result is that suppliers of reserve capacity have difficulty predicting their potential revenues. A provider of spinning reserve, for example, that has a very low energy price may or may not be dispatched to provide energy. This was a frequently heard criticism of the ISO's operating procedures in our telephone interviews and public meetings.

The ambiguities in the usage of units providing reserve capacity are exacerbated by compliance problems. ISO operators have indicated that several units that are receiving reserve payments are conducting uninstructed increases in their output. These units thereby collect the imbalance energy price in addition to their reserve payments, even though they are supposed to be providing only reserve. There is evidence that the current protocols for monitoring and punishing non-compliance have not been sufficient to deter such behavior.

Another ISO dispatch practice that several market participants have protested against is the acquisition by the ISO of reserves and energy from outside of the ISO control area through a process of negotiation. The ISO operators have at times relied upon negotiated agreements with neighboring control areas when the operators have received either a shortfall or an excess of supply through the standard market processes. The ISO states that it has the right to turn to negotiations with outside areas to fill areas of need not met by its markets. Some stakeholders claim that the conditions under which these negotiations occur are sometimes not true shortfalls and that this process discriminates against firms inside the control area who do not receive the same consideration for negotiated agreements. We are not familiar enough with the relevant tariff protocols to judge the veracity of these claims, but we do observe that some degree of consumer flexibility on the part of the ISO is an effective defense against the exercise of market power. At the same time, it would be desirable to increase the transparency of the decision process of the ISO's recourse to outside negotiations. A possible alternative discussed in Section 5 is a set of longer term agreements under which the ISO might acquire resources and for which suppliers both within and outside the ISO control area could compete.

4.7. Flawed Allocation of Ancillary Service Costs to Scheduling Coordinators

Another distortion of the ancillary service market is the manner in which the ancillary services are paid for. Currently, all ancillary service costs are allocated pro-rata according to *day-ahead* schedules. Thus, the cost burden for reserves is shared according to the level scheduling coordinators *say* they are going to use the system, and not according to the level that they *actually* use the system. The current billing practice gives firms an incentive to under-schedule, because doing so reduces the amount of ancillary services the firms have to pay for.

Figure 16 illustrates the difference between the day-ahead scheduled daily load and the hour-ahead scheduled load for the same day. Day-ahead loads schedules have consistently understated the hour-ahead schedules all weekdays except Mondays. The magnitude of this difference has been increasing as ancillary service prices have continued to stay at the currently high levels (note the scale on right-hand axis).

It was originally thought that the creation of a replacement reserve product would help deter under-scheduling. The tariff intended that replacement capacity would be paid for only by the firms who produce less generation than they had scheduled, thereby placing the cost burden to the system from under-scheduling onto the firms that had caused the problem. However, software shortcomings have prevented the implementation of this intent. Additionally, under-scheduling increases the amount of replacement reserve that the ISO needs to procure. So a firm can potentially reduce its own ancillary service payments *and* increase its sales of replacement reserves by scheduling less than its anticipated demand.

4.8. Exclusion of Suppliers from Outside of the ISO Control Area

Until August 6, the ISO could not accept ancillary service bids from any supplier located outside of the ISO control area, due to limitations in the bidding software. This represents a significant reduction in the pool of potential suppliers to the ancillary services market. By comparison, the share of *energy* scheduled in the ISO system that has originated from outside the ISO control area has at times reached up to 20%. On August 5, some of these barriers were removed, and suppliers from outside the ISO have since been able to bid into all ancillary service markets except regulation. The regulation market will remain open only to suppliers from within the ISO due to the more demanding physical requirements of that service. In addition to ISO software constraints, several municipal utilities also face contractual barriers to providing ancillary services to the ISO.[31]

[31] Several municipal utilities have signed interconnection agreements with neighboring (or surrounding) IOUs that include both monetary and operational constraints which make it difficult for these firms to export ancillary services through those interconnected transmission facilities.

It is important to note, however, that suppliers from outside the ISO control area could have an *indirect* impact on the ancillary services market. In the absence of other distortions, we would expect to see suppliers from inside the ISO control area respond to high ancillary service prices by shifting capacity from the PX (and other SCs) into the ancillary service markets. This would in turn increase the energy price in the PX and, absent congestion, draw increased supply from *outside* the ISO. As with the energy market, transmission limitations and high out-of-ISO demand can limit the amount of capacity available for export into either the ISO or the PX.

4.9. Other Software Difficulties

Several software problems have been identified either by the ISO or market participants. It is our understanding that corrections to most of these software problems are universally desired and therefore not controversial, although the priority given to the various software fixes is still a subject of debate. These problems are listed below. A description of each of these problems provided to us by the ISO is attached as Appendix A of this report.

It is important to note that confusion *about* many of the software issues has impacted the market almost as much as the problems themselves. We advise that the ISO establish an outlet through which stakeholders can notify the ISO of software problems and from which they can receive information about the progress of software fixes. This would ideally include clear notification of when and how the various problems have been corrected. This outlet should be an easy to access and transparent, and could perhaps be added to the ISO web site. In addition to progress reports, the ISO could use this outlet to help establish priorities amongst stakeholders for various software fixes. Many of the comments and complaints of market participants that have been received by the Market Surveillance Committee could have been addressed by this kind of procedure.

1. Inability of the Real-time Dispatch Software (BEEP) to Track Operator Dispatch Instructions
2. Mishandling of Downward Regulation in Sequential Ancillary Service Evaluation
3. Inadequate Verification of Eligibility of Ancillary Service Bids
4. Lack of Coordination between Congestion Management and Ancillary Services Management Software
5. Settling Ancillary Service Responsibility based on Scheduled rather than Actual Load
6. Improper Settlement for Replacement Reserves
7. Lack of Proper Coordination Between ISO's Dispatch and Automatic Control Software
8. Lack of 10-Minute Real-time Price Information
9. Failure to Track Uninstructed Deviations using Reserved Capacity
10. Improper Payment for Uninstructed Deviations
11. Ignoring Impact of Ancillary services on Congestion
12. Lack of Explicit Requirement for Downward Regulation

5. Recommendations

In this section, we list a number of options for addressing many of the problems described in Section 3. We focus here on policy and market design modifications that should be viewed as additional proposals beyond the correction of the various software-based problems that have impacted the market. The benefits of some of these proposals, such as a state-wide auction for ancillary services, will be further illuminated once we have completed our broader empirical analysis of the performance of these markets using the data obtained from the ISO's Market Surveillance Unit. The impact of several of the proposals may also depend upon the implementation of others. For example, we do not recommend giving to all participants the right to receive market-based rates unless the ISO has the right to impose a damage-control price-cap that will permit it to reject excessive bids. This price cap makes explicit the usual right that all buyers have, and the ISO should be no exception, to refuse to purchase at excessive prices. The ISO should be able to raise or lower the cap as it sees fit based on periodic review of the performance of the markets. We feel that all of these proposals represent steps in the right direction toward a better functioning market.

- 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.

- Revise RMR protocols and rates so that generating units with RMR contracts no longer have the incentive to withhold capacity from the day-ahead energy market and ancillary services markets in order to be called under their RMR contracts. This could involve creating a new class of true option contracts to replace some RMRs.

- Grant market-based rates for ancillary services for all market participants, assuming the ISO retains the authority to impose a damage control price cap. This could also be accompanied by, or contingent upon, the commitment of some of the capacity of PG&E to contracts for differences for the provision of ancillary services

- 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

- Run the auction for ancillary services on a state-wide basis. If the state-wide market-clearing prices leaves a shortfall of supply in a given zone, use RMR contracts to make up the shortfall

- Revise scheduling and/or energy imbalance protocols to help reduce the need for regulation capacity.

5.1. Adopt Rational and Transparent Purchasing Practices

No matter what other regulatory or procedural changes are made to these markets, the rigidities in the current protocols for purchasing ancillary services should be removed. We recommend that the ISO adopt the common sense rule of applying a bid to supply a higher quality ancillary service to the provision of a lower quality ancillary service when doing so reduces purchase costs. Thus, the ISO would have the discretion to substitute extra regulation capacity for spin capacity, if this unused regulation capacity was bid in at lower prices than the spin capacity. It could also substitute unused regulation or spin capacity for non-spin capacity, if either of the first two services were bid in at lower prices than non-spinning reserve. Finally, any unused regulation, spinning and non-spinning reserve capacity could be purchased instead of replacement capacity if any of these three services were offered at lower prices than replacement reserve capacity.

Although there are several complications associated with implementing rational purchasing within the context the current ISO protocols, all of the market participants we talked to both in our telephone interviews on August 10 and at the open meeting of the Market Surveillance Committee on August 12 supported allowing the ISO this sort of discretion in procuring its ancillary services requirements.

One complication associated with implementing this rational buyer strategy for the ISO is that the *energy* payments made to generators for regulation capacity differ from those made to generators providing other ancillary services. Suppliers of regulation are compensated through the REPA mechanism because they cannot receive the real-time energy price for electricity supplied from their units. We are currently studying various proposals for making the ISO a more rational buyer of ancillary services in a manner consistent with statements from the ISO tariff quoted in Section 4.3. In the meantime, a few straightforward changes in the ISO's ancillary services procurement protocols can move it significantly closer to rational buyer market outcomes.

A straightforward method for introducing some buyer rationality into the ISO's purchasing process would be to impose the requirement on market participants that all bids for superior services also to apply to the provision of inferior ones. For example, if a firm bid a block of capacity at a given price into the spinning reserve market, that block is also eligible to provide non-spin and replacement reserve from this capacity if it is not taken in the spinning reserve auction. It would be rolled over to the bid stack for any inferior product, at the same price that it had been offered for spin. Alternatively, the ISO could just buy more spin, if it were cheaper than non-spin, and substitute it for non-spin. In either case, the cost to the ISO is the same. However, since it is reasonable to assume that, for a given unit, the cost of providing these services is declining across the hierarchy (regulation, spin, non-spin, replacement), a generator offering spinning reserve capacity at price of $10/MW would prefer to receive that price for providing non-spinning or replacement reserve.[32] It would therefore improve the economic efficiency of the ancillary

[32] This assumes that the unit will be dispatched in the real-time energy bid stack according to its energy

services markets to let that unit provide the inferior service at the price offered for the superior service. Imposing this requirement on bids submitted by each generating unit to the four ancillary services markets, would guarantee that the four total hourly bid quantities plotted in Figure 12 and 13 would never cross. The total hourly amount of regulation bids submitted would always be less than the total hourly quantity of spin bids, and so on. The total hourly amount of replacement bids greater than that value for all other ancillary services.

Given that the cost of supplying these services should decline as one moves from higher to lower quality services, firms would ideally submit *lower price* bids to the ISO for the supply of a lower quality service after that capacity lost at a higher price in the auction for the higher quality service. For example, if a generator submitted 100 MW that was not accepted for the supply of regulation at $50, and the capacity is then rolled over into the spinning reserve market, that generator would want to lower the price of that unit in order to increase its chance of earning some revenues from it in the lower quality markets. To capture this aspect of bidding based on the cost of supply, the ISO should allow firms to lower the price of their bids if those bids are rolled over into a market for a lower quantity service. However, we recognize that allowing for this possibility would significantly increase the number of prices that each unit would be required to submit. In particular, there would be a bid price for capacity explicitly bid into each market and a bid price for capacity that was bid into a higher quality market not taken and therefore available for a lower quality market. Rather than increase the number of bid prices each unit can submit, we feel that the much of the increase in market efficiency made possible allowing bid prices lower quality service markets for capacity not taken in higher quality services can be captured within the constraints of the current ISO bid software by imposing the requirement on each generating unit that the capacity price bid for a lower quality service may not exceed the price bid for the next higher quality service. Under this restriction, all capacity not taken in a higher quality product auction will be available to be taken in a lower quality auction at a bid price that is less than or equal to price that it lost at in the higher quality auction.

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bid with the same probability regardless of whether the capacity is used for spin, non-spin or replacement reserve. The assumption of an equal probability of being dispatched in the real-time energy market across the spin, non-spin and replacement capacity markets is a necessary condition to claim this improvement in economic efficiency.

These two changes to the ISO's purchasing protocols are summarized below.[33]

Rational Buyer Protocol

1. **For each generating unit, the total quantity of capacity bid for the supply of each ancillary service cannot decrease as a quality of the ancillary service product decreases.**

2. **For each generating unit, starting with the highest quality ancillary service product that has a non-zero capacity bid, the bid prices associated with that ancillary service product and all lower quality ancillary service products must not increase as the quality of the ancillary service product decreases.**

Thus for a generating facility offering capacities, q_{reg}, q_{spin}, q_{non} and q_{repl}, for the supply of regulation, spin, non-spin, and replacement, respectively, the ISO should require that $q_{reg} \leq q_{spin} \leq q_{non} \leq q_{repl}$ and that $p_{reg} \geq p_{spin} \geq p_{non} \geq p_{repl},$ where p is the bid price for these respective services from that generating unit. This protocol change would require a simple bid consistency check on a unit-by-unit basis for the satisfaction of these inequalities before the data enters the ISO's current market-clearing process for the ancillary services markets.

In order to implement meaningful substitution between reserve services, the payment mechanisms for these services must be consistent. Ideally, this would mean that every firm would be eligible for market-based rates, thereby rendering REPA unnecessary. Although the rational buyer requirement on generator bids could still be implemented if REPA remained a component of compensation for regulation providers, we do not recommend this course of action. The REPA simply substitutes an administratively determined additional payment to winning bidder in the regulation auction. We instead recommend that REPA should be eliminated, the rational buyer requirements on generator bids imposed, and market-processes be allowed to set the price of providing regulation, subject to a damage control price cap.

In addition to adding flexibility to the ISO's purchasing protocols, it is important that these protocols be transparent to market participants. Bidders into these markets must be able to formulate accurate expectations the revenue they can expect to earn from a given bidding strategy in order for the market to operate effectively. This is especially true for the provision of imbalance energy. As discussed earlier, generators providing spin and non-spinning reserve are uncertain of the mechanism used to dispatch them in the real-

[33] This change in bid protocols will allow the ISO to retain it current market-clearing processes yet increase the frequency of hourly ancillary services prices that have higher-quality services priced higher than the lower quality services. This rational buyer protocol should therefore only be in effect until the appropriate fully rational, total cost-minimizing ancillary services procurement process can be designed and implemented.

time energy market, because the operators often skip over energy bids from spin and non-spin units in the real-time energy bid stack. The ISO should clarify, to the greatest extent possible, the conditions under which spinning and non-spinning resources can be called upon to provide imbalance energy. At the same time, the ISO may wish to consider whether it is possible to reduce the overall need for the various ancillary services, especially replacement reserve. No matter what is viewed to be the appropriate need for and usage of ancillary services, it is important that the protocols for usage are clear to all market participants.

One method the ISO may wish to consider for resolving the ambiguities surrounding the usage of capacity reserves for the supply of imbalance energy is the application of a fixed "adder" to the energy price of generation units providing a given service. Each ancillary service could have a different adder value, set to approximate the opportunity cost of replacing that reserve. This value could be set at the day-ahead market-clearing price for that hour for the capacity of that ancillary service, or there could simply be fixed adder for all hours of the day for each ancillary services energy bid. To take a concrete example, suppose the day-ahead price of non-spinning reserve capacity was set at $10/MW. A spinning reserve unit that had won in the day-ahead capacity auction would then have $10/MWh added to its real-time energy bid when it is placed in the real-time energy bid stack. Suppose this facility's real-time energy bid was $20/MWh, then its price in the real-time energy bid stack would be $30/MWh, and it would only be dispatched if the real-time energy price exceeded $30/MWh, not its bid of $20/MWh. The use of this adder places a dollar value on the opportunity cost of spinning and non-spinning reserve units in the real-time energy bid stack. The replacement reserve capacity would have no adder in the real-time energy market under this scheme. This scheme has the benefit that firms bidding into the spinning and non-spinning reserve markets will have an incentive to bid low for the real-time energy portion of these ancillary services bids. There will also be an additional incentive for firms to keep the market clearing capacity prices for the non-spinning and replacement reserve markets down in order to reduce the adder on the energy bids associated with their spinning and non-spinning reserve units.

5.2. Revise or Supplement the Existing RMR Contracts

As described in section 4.4, RMR contracts in their current form have done very little to reduce market power problems, and are most likely contributing to them. Recall the negative relationship between the frequency of market participation by generating facility and the level of its RMR capacity payments discussed earlier. The frequency and severity of these problems is a question we would like to study further. However, it is clear that the ISO would benefit from additional flexibility in purchasing services either under RMR contracts or some other type of contract that could, for some units, be substituted for RMRs. The ISO would also benefit from reducing the incentive to withhold capacity from the market that some RMR contracts appear to give to their owners. Owners of RMR units have protested that allowing the ISO to arbitrarily call their units under RMR terms would discriminate against lower cost units that would otherwise be earning legitimate operating profits. This is a valid and important point. However, RMR contracts should be modified to both reduce their negative impacts on the market and provide the ISO with more flexibility.

One possible modification that would reduce many of the perverse incentives for withholding capacity from the ISO's ancillary services markets in the current contracts would be to treat the RMR contract as a reliability insurance policy purchased by the ISO from a generating facility. The ISO would pay, at the beginning of the contract period,[34] a non-refundable, up-front payment to the unit's owner, that both parties deem to be a 'fair.' The ISO would then gain the right to call on this unit for local grid reliability reasons and to provide ancillary services. This fixed payment or reliability insurance premium would be independent of the number of hours in which the unit actually operates. It should be designed to pay the unit owner a sufficiently large fraction of its fixed costs, that it is willing to be called under an RMR contract.

It may appear that, under this arrangement, the ISO would pay a larger share of the unit's fixed costs if that unit were called upon less than was expected. However, under existing RMR contracts the generators themselves, through the bidding (or not bidding) of their units, can directly influence how many hours the unit is called under an RMR contract. Under the current contract terms, it is our understanding that from discussions with the ISO Market Surveillance Unit that almost no units are called *less* than expected, and many are called far more than was expected. With an up-front payment of fixed costs, the RMR units would most likely receive no more fixed cost compensation than they do now, but would not have to distort the market through the non-bidding of their units in order to do so.

Under a reliability insurance policy, the ISO would be further obligated to pay the unit's variable cost for every hour in which it operates under a RMR contract. If necessary, the conditions under which the unit would be called could be limited to some form of 'market first' criterion, as long as the market upon which that criterion is based is shown to be workably competitive. Under the scheme in which the RMR is only compensated for its variable cost of providing energy under the RMR contract, generators owning units with this type of reliability insurance policy would have extremely strong incentives to bid into the market during hours when they expect the PX or real-time price to be in excess of their variable cost of producing electricity, because they will only cover their variable operating costs if they are called under an this contract, but may earn far in excess of this amount if they called in the PX or real-time energy market.

The ISO would also benefit from contracts for the provision of ancillary services that it could invoke for economic, rather than reliability based reasons. If RMR contracts must include a 'market-first' provision, a new type of contract could be created. Hopefully, the existence of a second type of contract that would help fill *general*, rather

[34] The payments could also be made in monthly installments over the duration of the contract.

than location specific ancillary service needs, would reduce the number of RMR contracts that would be needed. The price of these contracts could be based upon market-based, rather than cost-based arrangements. Expanding the menu of ancillary services contract only be should be pursued if the ISO decides to continue with its current policy of paying for some of the unit's fixed costs through a variable capacity payment per MW called under the RMR contract. However, we believe that reform of the RMR contracts to provide owners of these units with strong incentives to bid aggressively into the ancillary services markets during periods of high system demand, will go a long way towards making the less markets workably competitive.

5.3. Grant Market-Based Rates for all Market Participants

It will be very difficult for prices in the many interconnected markets of California's electricity industry to equilibrate if regulatory price-caps are applied unevenly across firms and across markets. Therefore the elimination of cost-based caps for the remaining firms that are subject to them is a precondition for the markets to reach their intended form. There are valid arguments on both sides of the question of whether to grant market-based rates to all firms. Even after the divestiture of some of its gas-fired generation, Pacific Gas & Electric still has ownership over half of the 10-minute ramping capacity in the ISO system. PG&E is likely to be a pivotal supplier of both regulation and spinning reserve a large portion of the time. We are currently examining the number of hours in which PG&E (and other firms) are currently pivotal bidders in these markets.[35] PG&E controls large shares of the ancillary service capacity in the northern California zone.

However, it seems reasonable that the decision to let a market process determine prices for a given product should be made on a market-wide, not firm by firm basis, so long as the ISO retains the authority to impose a damage control price cap (as we recommend below). If a market is viewed to be workably competitive, all firms should be eligible for market-based rates. All firms are eligible for market based rates in the much larger market for electrical energy as well as the replacement reserve market. Additionally, PG&E is the largest *consumer* of ancillary services and is also subject to a rate freeze through the year 2000. These same factors that contribute to muting PG&E's incentive to exercise market power in those markets also apply to the remaining partially regulated markets.

If PG&E is considered to control too dominant a share of the ancillary service capacity to permit market-based rates in these markets, an alternative is to place some of

[35] This calculation involves, for each firm, subtracting the total capacity bid by all *other* firms from the market requirement for each service. If the market requirement is greater than the capacity offered by all other firms, that firm is pivotal. A pivotal firm can receive any (uncapped) price it bids for that capacity. This calculation is often much more informative than market share calculations as a firm could be pivotal but still have a very small market share.

this capacity under either financial or physical vesting contracts until it is divested. With such a contract, the ISO, or other parties, would be entitled to a fixed amount certain ancillary services under preset "reasonable" prices. These contracts could be physical call options or even contracts for differences. In many ways, RMR contracts have indirectly served this purpose. However, as described above, the extremely lucrative terms of these contracts and the restrictive conditions under which they can be used combine to exacerbate, rather than mitigate, market power problems.

We favor purely financial contracts for differences (CFDs) for a fixed pre-determined yearly pattern of ancillary services quantities. We favor offering the signing of such contracts as a pre-condition for granting market-based rates to the remaining regulated firms. Contracts such as these have been successfully utilized, in one form or another, as a tool for mitigating market power in several electricity markets throughout the world.[36] These contracts can provide a level of insurance against market power abuse and other market design problems that RMRs currently have not provided.

Ancillary Services Contract for Differences (CFD)

An ancillary services contract for differences works as follows. Suppose a generator sells a 20 MW worth of CFDs at a price of $10/MW in the replacement reserve market. If the market price for replacement happens to be $20/MW then the generator owner pays to the purchaser the difference between the market price of $20/MW and the CFD price of $10/MW times the quantity of CFDs sold, 20 MW. This means that if the market price is instead $5/MW, the purchaser of the CFD pays to the generator difference between the CFD price of $10/MW and the market price of $5/MW times the number of CFDs sold 20 MW.

Under an ancillary services CFD, a generation owner would agree to a negotiated pattern of hourly prices throughout the year or a single price for all hours during year for each ancillary service. Associated with each of these contracts is a pattern of hourly CFD quantities throughout the year. To continue our example, suppose that at a market price of $20/MW the generator was only able to sell 15 MW of its capacity in this market, and suppose for simplicity the marginal cost of supplying replacement reserve is zero. Consequently, this generator's combined profits from its sales in the actual replacement reserve market and the CFD contracts that it owns is equal to the market price of $10/MW times the quantity sold in the replacement market, 15 MW, minus the market price of $20/MW less the CFD price of $10/MW times the quantity of CFDs sold, 20 MW. The generator profits in this case are 10*15 – 5*(20) = $50. Now suppose that by bidding a lower price into the replacement reserve market the generator is able to sell 30 MW of capacity, but his greater supply lowers the market price to $5/MW. In this case the generator's profits from both its sales in the market and its CFD holdings is 5*30 +

[36] Such contracts have been utilized in the Alberta, United Kingdom, and Australia electricity markets. For an examination of their impact in the UK, see Newbery, David "Power Markets and Market Power," *The Energy Journal* 16(3).

5*20 = $250. In this case the generator makes money from actual sales in the replacement market and earns difference payments because the market price is less than its CFD price.

This example, exhibits a general phenomenon associated with CFDs. They provide strong incentives for firms to bid very low prices in order to both sell more than the CFD quantity in the actual physical market for the commodity. In this way CFDs provide a way to mitigate the incentive suppliers have to set high prices. This example, also illustrates why it is important to make the pattern of ancillary services quantities throughout the year follow the actual pattern of ancillary services that the net demanders of ancillary services expect to purchase from the net supplier of ancillary services.

By purchasing a sufficient quantity of CFD contracts, the net buyers of ancillary services can significantly mute the incentives of sellers to set high prices in the ancillary services markets. As shown earlier in the report, in general, firms attempt to set high prices by withholding some capacity the market. A firm that does this hopes that prices driven high enough to offset the lost quantity that the firm has sold. However, if a generating firm has sold a substantial quantity of CFDs it incentives to engage in this behavior are substantially reduced.[37]

The larger the quantity of CFDs a generator holds relative to its sales in the physical market, the greater its incentives are to bid aggressively to set a low price in the market in order collect difference payments from the sellers of the CFDs. The benefits associated with aggressive bidding from generators selling large quantities of CFDs are particularly great for the spin, non-spin and replacement reserve markets because the cost of supplying these services is presumably much less than the cost of supplying regulation or energy.

5.4. Retain a Damage Control Price Cap

Although the ultimate goal of regulators and stakeholders is to let market processes determine prices for electricity services in the California market, it is clear that there are currently flaws in the design and implementation of these markets. While these flaws are being identified and corrected, it is prudent to have a backstop on which to rely upon. The various price caps that the ISO has to date imposed have been set at levels that hopefully would not be binding if the market functions as intended. The caps are in place to limit the extent to which individual firms can take advantage of market flaws. These markets continue to evolve and this report has identified several steps that could be taken to help it evolve further. While changes such as the ones proposed here are being implemented, and until participants are fully comfortable that most significant market problems have been corrected the need for damage control price caps remains. Further

[37]Because the generator is effectively short in the ancillary services market if in any hour it is unable sell the quantity of ancillary services specified in the CFD, its incentive is to set as low a price as possible in the physical market so that it receives difference payments from purchaser of the CFDs

attention needs to be given to the question of whether the current level of the price cap is appropriate, and to developing methodologies for setting the cap.

5.5. Purchase Ancillary Services Using a State-Wide Auction

While the markets for ancillary services may at times be competitive on a state-wide basis, there is no question that the competitiveness of these markets is reduced when purchases are made by zone, rather than statewide. We are currently evaluating the relative competitiveness of both zonal markets relative to the statewide market using several measures. One way to mitigate the abuse of zone specific, locational market power is to always purchase services through a state-wide auction. This would produce a state-wide market clearing price for each ancillary service. If this price produces more services in one zone, and less services in the other, than are required, RMR contracts could be used to make up the difference in the zone with the shortfall.

The following example illustrates how this might be accomplished. Assume that a single firm owns all the ancillary service capacity in zone A, and that several firms compete to provide ancillary services in zone B. Further assume that the ISO needs to procure 2000 MW. However, with congestion, the actual location specific need for ancillary services is 1000 MW in each zone. If purchased on a zonal basis, the firm in zone A could exercise monopoly power and, given demand inflexibility, force prices to always be equal to whatever limits were imposed, say $250. Assume that the firms have the following characteristics.

Firm	**Zone**	**Unit Name**	**Capacity**	**Bid**
1	A	Alpha_1	500	10
1	A	Alpha_2	500	250
1	A	Beta_1	500	250
2	B	Delta_1	500	25
2	B	Delta_2	500	30
3	B	Gamma_1	250	10
3	B	Gamma_2	250	20
4	B	Epsilon_1	500	15
4	B	Epsilon_2	500	30
5	B	Eta	250	250

Table 7: Sample Firm Characteristics

Given the above unit capacities and bids, if the ISO conducted its auction on a zonal basis firm 1 would be awarded all 1000 MW of capacity in zone A at a price equal to the market limit. Note that firm 1 is *in the market* with all its units, so that the ISO could not call upon any of these units under current RMR protocols. This is an extreme example of how RMRs do not help the problem of local market power if the market is defined to be too small. Competition is quite robust in zone B, with firms 3 and 4 each supplying 500 MW at a market clearing price of $20, set by firm 3.

Purchase Protocol	**Zone A**		**Zone B**	
	Marginal Unit	Price	Marginal Unit	Price
Zonal	Alpha_2	$250	Gamma_2	$20
Merged	Delta_1*	$25	Delta_1	$25

*This unit would set the price but not be called upon to provide reserves.

Table 8: Sample Market Outcomes

If, however, the auction were combined to draw supply from *both* zones A and B, the bid stacks of all firms would be combined. Using the above bids, 2000 MW of supply would be reached with 500 MW each being supplied by firms 1, 2, 3, and 4. The market clearing price would be set by firm 2 at $25. Firm 1's attempt to set the price at $250 would be undermined by the aggressive bidding of firms in zone B. This allocation of supply, however, would result in 1500 MW in zone B and only 500 MW in zone A, where an additional 500 MW would be needed. Under such a circumstance, only 1000 MW would actually be purchased in zone B (the same as before) at a price of $25. The remaining units in zone A are now *out of the market* due to their high bid prices. One of these units would be called to serve the shortfall under an RMR contract.

This example illustrates how it is necessary to enlarge the market in order for RMRs to begin to function in the manner in which they were intended. If a zonal market is not sufficiently competitive, then RMRs will not help to mitigate market power when reserves are acquired on a zonal basis. Note that in the example given above, firm 1 would benefit from changing the bids of its remaining units to $20, which is the market clearing price in zone B at 1000 MW of supply.[38] Thus, in this example, merging the zones helps encourage more aggressive bidding on the part of some firms.

5.6 Revise protocols to help reduce the need for regulation services

Because of the amount of input and comment we received during our telephone interviews and public meetings on the larger than expected purchases of regulation capacity by the ISO, we felt this was an issue worthy of further study and public comment. Because no committee member is an expert in power systems engineering, we can offer no concrete recommendations for changes in operator protocols. Nevertheless, would like to continue our dialogue with the ISO's operations staff in order to better understand this very complex problem.

We do have one recommendation in regard to this topic. Many countries around the world have restructured their electricity industries to some extent. The operational experiences of these electricity supply industries both before and after restructuring may enable the ISO to provide an answer to the question of whether or not their operators are procuring "too much" regulation, or if the operating a competitive electricity market simply requires significantly more regulation reserve. In addition, the experiences of these countries in reducing their ancillary services purchases over time, offers the ISO the opportunity to benefit from these experiences and more rapidly reduce its own demand for regulation.

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[38] This analysis assumes that RMR prices are set at reasonable levels, if the RMR rates on all these units were very high they would most likely stay out of the market intentionally in order to collect this more lucrative payment. This problem is discussed in section 3.4.

6. Conclusions

Rather than reproduce the summary of our recommendations, the committee would like to instead re-affirm its conviction that the PX and ISO energy markets and the ancillary services markets can be made workably competitive. We believe that the adoption of the recommendations contained in this report can put the ISO on track to achieve its goal of competitive markets for electricity. On the other hand, these markets are rapidly evolving in terms of both the numbers, sizes and strategies pursued by market participants, so that the process of ensuring this transition to competition remains on track is ongoing and requires periodic detailed analysis of market data. This will allow the ISO management to anticipate many market power and other structural problems with the market before they occur. For that reason, we hope to continue research on the topics for future investigation described throughout this report.

Appendix A: Description of Software Related Problems

This attachment describes various other software related problems that have been hindering performance in the ISO's markets. These problems have been identified either by the ISO or market participants.

1. Inability of the Real-time Dispatch Software (BEEP) to Track Operator Dispatch Instructions

   The ISO real-time dispatch software (Balancing Energy and Ex-post Pricing; BEEP) runs every 10 minutes, but its dispatch instructions for the non-AGC units are not executed automatically. For many resources in the BEEP stack, instructions must be communicated by voice to the field to increase or decrease generation as instructed by BEEP. The 10-minute interval between two successive BEEP executions is sometimes inadequate to permit the ISO operators to complete this manual process for all units designated by BEEP. However, BEEP assumes its instructions are implemented, interprets the outstanding imbalance as new imbalance energy, and moves up the BEEP stack to higher priced energy bids to dispatch additional energy in the subsequent 10-minute interval. This may result in higher and more volatile real-time prices. It also reduces the available supply of real-time imbalance energy. This deficiency was the primary reason for imposing the real-time energy bid price cap as a precondition for the transfer of operational responsibility to the ISO at start-up.

   A fix is due to be implemented in the forthcoming release of the BEEP software to allow the ISO operator to indicate the units called, and to have BEEP throw back into the BEEP stack those energy segments that it selected but the ISO dispatcher did not succeed to call. In the mean time the ISO has implemented a manual process whereby the ISO dispatcher can manually adjust (bias) the amount of imbalance energy seen by BEEP, based on their estimate of the amount of MW instructed by BEEP that could not be implemented in the field. This manual workaround has partially mitigated the problem to some extent.

2. Mishandling of Downward Regulation in Sequential Ancillary Service Evaluation

   The Ancillary Services Management (ASM) software processes ancillary service capacity bids sequentially in the following order: Regulation, Spin, Non-spin, and Replacement. The capacity selected from a unit for each market is subtracted from the total capacity available from that unit for the market processed next in the sequence. However, the software does not distinguish between downward and upward regulation ranges in computing the available capacity for the next market. For example, consider a 250 MW unit with a ramp rate of 20 MW/min that has won a day-ahead energy schedule of 150 MWh for a given hour. This unit may wish to bid ±50 MW in the regulation market (50 MW upward and 50 MW downward), and to have its remaining 50 MW capacity bid into the spin market. If this unit is selected in the regulation market, its total range of regulation (from -50 MW to +50 MW, i.e., a total of 100 MW) is subtracted from the available capacity, disallowing its remaining available 50 MW capacity bid to the spin market.

A fix is being implemented to correct the problem before the end of August 1998.

3. Inadequate Verification of Eligibility of Ancillary Service Bids

At present there is no verification in the Ancillary Services Management (ASM) software to ensure the capacity bid from a unit into the ancillary services market is in fact available. For example a 720 MW unit with an energy schedule of 460 MW could bid and win 240 MW of spin capacity in the day-ahead market and 240 MW of non-spin capacity in the hour ahead market, although the sum of its energy and ancillary service schedules (460 + 240 + 240 = 940 MW) exceeds its capacity (720 MW).

A fix is being implemented to correct the problem before the end of August 1998.

4. Lack of Coordination between Congestion Management and Ancillary Services Management Software

Currently the final schedules processed by the Congestion Management (CONG) software are not used in the Ancillary Services (A/S) bid evaluation. This may result in an A/S capacity schedule that is inconsistent and infeasible with the final energy schedule. This software deficiency was the basis for a temporary suspension of the penalty associated with the failure to provide ancillary services awarded in the day-ahead market, when the energy schedule is changed by CONG.

The Ancillary Services Management (ASM) software is being modified to consider unit final schedules, along with the unit physical limits and ramp rates in the release scheduled for the end of August 1998.

5. Settling Ancillary Service Responsibility based on Scheduled rather than Actual Load

At present the ancillary service capacity responsibility of each Scheduling Coordinator (to be self-provided or purchase from the ISO) is based on the SC's day-ahead (or hour-ahead) schedule rather than the actual load and generation. This has led to incentives for under-scheduling of load (and generation) in the day-ahead and hour-ahead markets, thus making it more difficult and costly for the ISO to operate the system reliably in real-time.

A change in the settlement software is contemplated to allocate ancillary service costs based on actual rather than scheduled load.

6. Improper Settlement for Replacement Reserves

The Settlement software at present allocates Replacement reserve capacity costs among the SCs in proportion to their scheduled loads. The proper settlement for Replacement reserve capacity would be based on the deviation between actual and scheduled load of each SC.

This change is contemplated as a future upgrade of the settlement software.

7. Lack of Proper Coordination Between ISO's Dispatch and Automatic Control Software

The real-time dispatch software (BEEP) is not closely coordinated with the Automatic Generation Control (AGC) software of the ISO Power Management (PMS) subsystem. BEEP uses fixed hourly schedules and load forecasts as reference. Although it perform a transition trajectory at the hour boundaries based on hourly schedules and load forecasts, it does not have any feedback from the field as to where each unit is actually operating. It assumes that all units are following their schedules and that the imbalance is mainly due to changes in system load and interchange. The generation deviations are sensed by BEEP indirectly through the impact of energy imbalance on the regulating units. This means that generation deviations are sensed only after regulating units (which are supposed to be "net-zero-energy" resources) have deviated rather largely from their base operating points (or Preferred Operating Point, POP). In other words, regulating units carry the burden of "load following" before BEEP starts calling upon other units to relieve the regulating units, allowing them to go back to their base point. A consequence of this is increased need for regulation reserve.

8. Lack of 10-Minute Real-time Price Information

Although BEEP computes 10-minute real-time imbalance energy prices, only the hourly average ex-post prices are published. Generators which are not under direct control (AGC) can (and do) deviate from their schedules or their Preferred Operating Points (POP) determined by the ISO. The generators are paid the real-time hourly average price for such uninstructed deviations. The uninstructed deviations are often intentionally maneuvered by the generator owners in reaction to real-time prices. The delayed (hourly) reaction of such generators to real-time price information may exacerbate the real-time energy imbalance fluctuations, and increase the need for regulating units which respond automatically and quickly to energy imbalance fluctuations. Publishing 10-minute prices will reduce the information time lag, provide for more timely response of generators to real-time prices, and hopefully reduce the amount of regulation capacity presently needed during shoulder hours.

Publication of 10-minute prices is scheduled in the forthcoming release of BEEP.

9. Failure to Track Uninstructed Deviations using Reserved Capacity

At present the software does not have the capability to recognize and penalize a generator that uses part of its capacity reserved for ancillary services (spin, non-spin, or replacement) to generate uninstructed energy in real-time. The ISO must resort to sporadic manual scrutiny of individual units to detect such problems.

10. Improper Payment for Uninstructed Deviations

At present BEEP uses the hourly average of the 10-minute imbalance energy prices to settle uninstructed deviations (computed as the difference between the hourly energy from the unit and its hourly schedule as modified by the BEEP 10-minute instructions). The 10-minute BEEP instructions are settled at the 10-minute Inc or dec prices as applicable (as if the instruction were followed). This process causes two problems:

Problem 1: The ISO will end up with a net loss in each hour. The following simple example demonstrates the point: For simplicity assume that there is an imbalance of +300 MW (surplus) in the first10-minute interval (i.e., an energy surplus of 50 MWh), and an imbalance of -1200 MW (deficit) during the second 10-minute interval (i.e., an energy deficit of 200 MWh) due to schedule deviations (uninstructed schedule changes). The ISO calls upon the most expensive decremental bid (say 6 $/MWh) for the first interval, and on the least expensive incremental bid (say 30 $/MWh) for the second interval. The second unit will thus be incremented by 900 MW (i.e., 150 MWh of energy) since BEEP will first restore the first unit to its original schedule before incrementing the second unit. The decremental price in the first 10-minute interval is 6 $/MWh; the incremental price in the second interval is 30 $/MWh. For the instructed deviations, the ISO charges the first unit 6*50 = $300, and pays the second unit 30*150 = $4500, a net payment of $4200. The hourly average imbalance energy price is (300+4500)/(50+150)= 24 $/MWh. Thus for the uninstructed deviations the ISO collects 200*24 - 50*24 = $3600. The ISO runs short by ($4200 - $3600), i.e., $600.

Problem 2: A gaming opportunity is provided since a unit is rewarded for not following the ISO instructions. In the above example, assume that the first unit does not obey ISO's instructions. It will have an uninstructed deviation (surplus) of 50 MWh for which it will get paid at the hourly average rate, 50*24 = $1200. Considering its payment to the ISO for its instructed decremental deviation (50*6 = $300), it will have a net gain of ($1200 - $300) = $900. In general, any unit that does not follow BEEP's instructions will end up with a positive net cash flow under the existing settlement process.

The source of both problems is using the average hourly price for uninstructed deviations. One way to correct the problem is to pay uninstructed excess generation (or under-consumption) the minimum of the 10-minute decremental prices for the hour, and charge the uninstructed under-generation (or over-consumption) based on the maximum of the 10-minute incremental prices for the hour. Regulation energy would still be settled at the average hourly ex-post price since it is under ISO's control (no maneuvering by the unit owners), and because the 10-minute reverse pricing for regulation energy could render the REPA payment inadequate as an incentive for participation into the regulation market.

11. Ignoring Impact of Ancillary services on Congestion

Presently the ASM and CONG software both ignore the potential impact of ancillary services on inter-zonal congestion within the ISO control area (e.g., Path 15). For example:

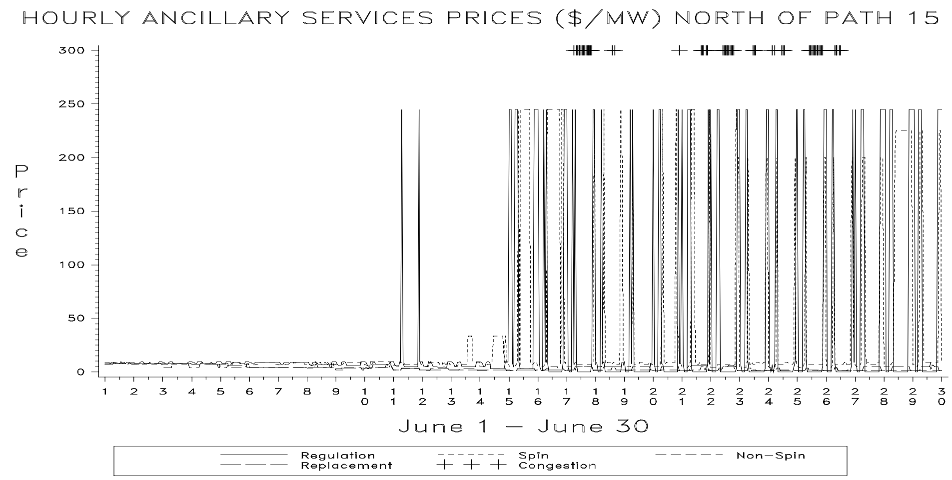
- If there is no congestion in the day-ahead, the ancillary services may be procured system-wide with no account for the fact that they may cause congestion if called upon.

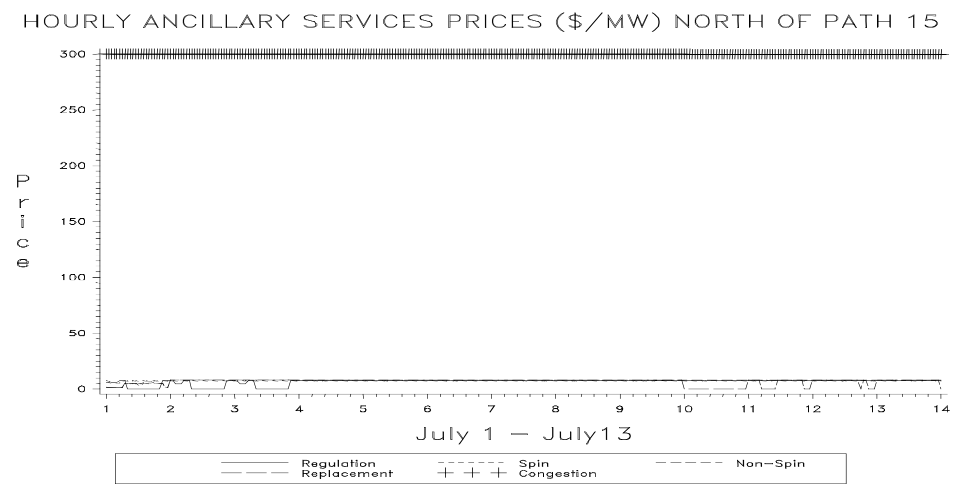
- If there is congestion in the day-ahead, the ancillary services must be procured on a zonal basis according to the current protocols, even if by system-wide procurement, they could possibly relieve congestion (by creating counter flows if called upon).

12. Lack of Explicit Requirement for Downward Regulation

At present the ISO does not have the software capability to state and procure the upward and downward regulation capability it needs. The requirement for regulation can be stated only as a percentage of the load without consideration of the direction of regulation. The ISO may end up paying for excessive regulation in a direction that it does not need, and/or may have to procure more regulation (or call upon RMR units) to ensure it does get adequate regulation capacity in each direction. The ISO software is under review to permit procurement of upward and downward regulation separately.

Figure 1


HOURLY ANCILLARY SERVICES PRICES ($/MW) NORTH OF PATH 15
Price
June 1 — June 30
Regulation
Spin
Non-Spin
Replacement
Congestion


HOURLY ANCILLARY SERVICES PRICES ($/MW) NORTH OF PATH 15
Price
July 1 — July13
Regulation
Spin
Non-Spin
Replacement
Congestion

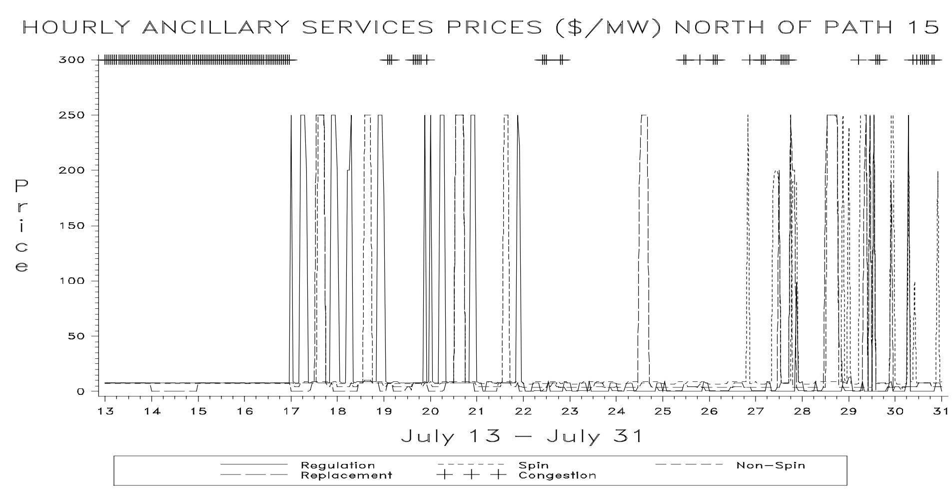
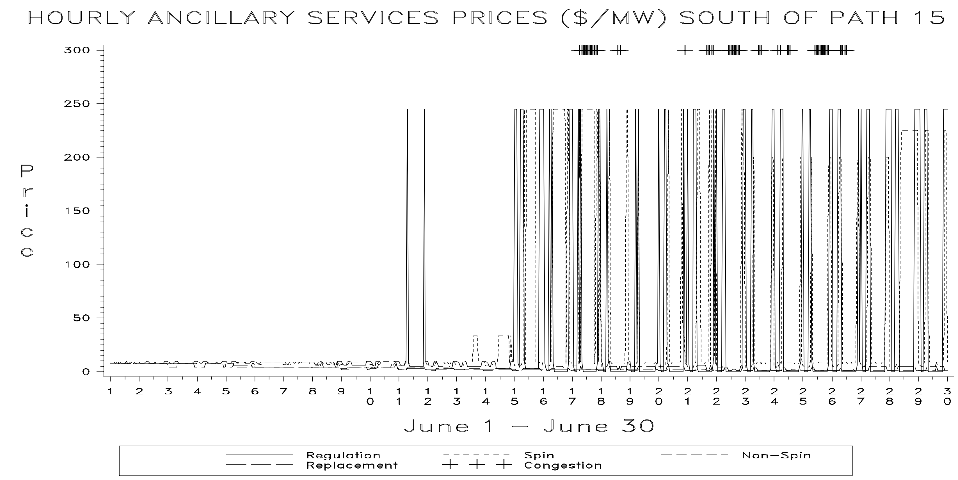
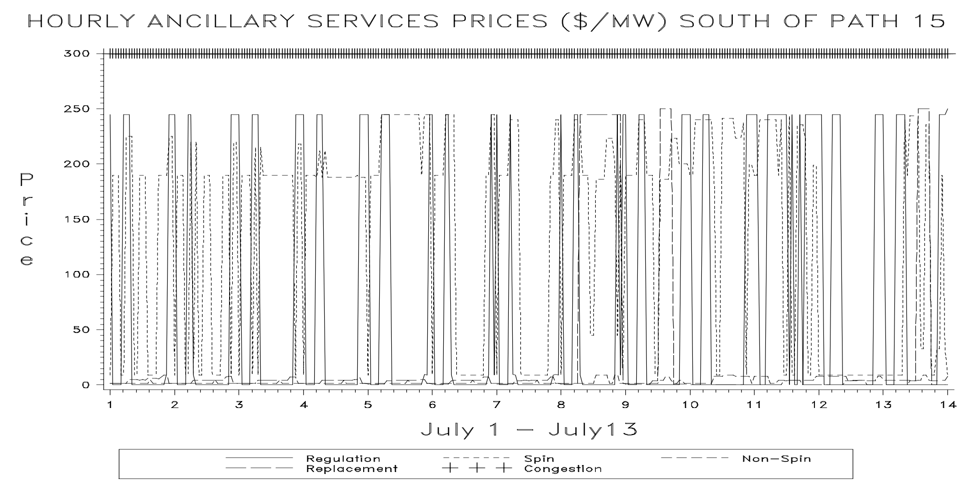

HOURLY ANCILLARY SERVICES PRICES ($/MW) NORTH OF PATH 15
Price
July 13 — July 31
Regulation
Spin
Non-Spin
Replacement
Congestion

Figure 2


HOURLY ANCILLARY SERVICES PRICES ($/MW) SOUTH OF PATH 15
Price
300
250
200
150
100
50
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
June 1 — June 30
Regulation
Spin
Non-Spin
Replacement
Congestion


HOURLY ANCILLARY SERVICES PRICES ($/MW) SOUTH OF PATH 15
Price
300
250
200
150
100
50
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14
July 1 — July13
Regulation
Spin
Non-Spin
Replacement
Congestion

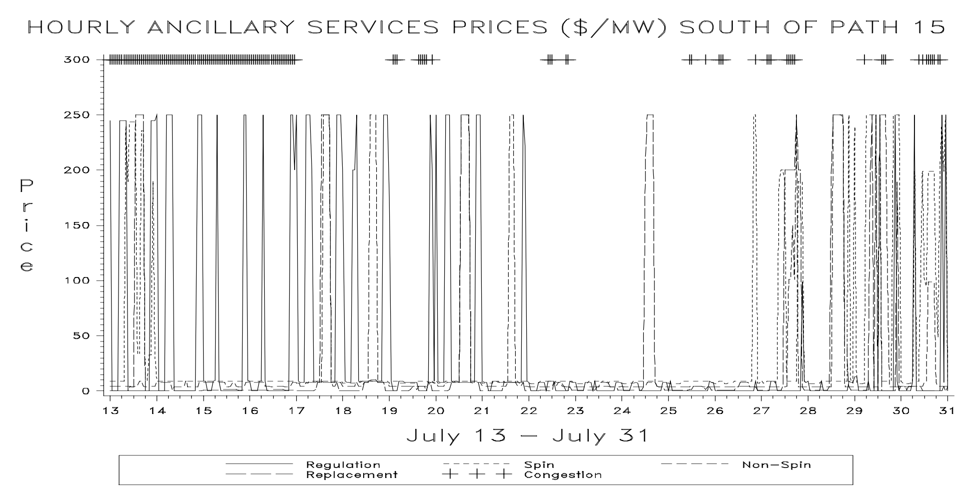
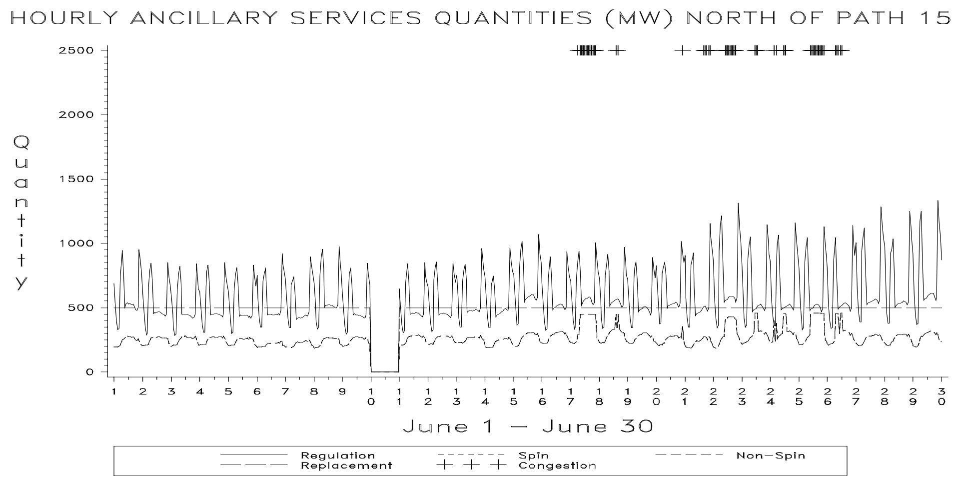
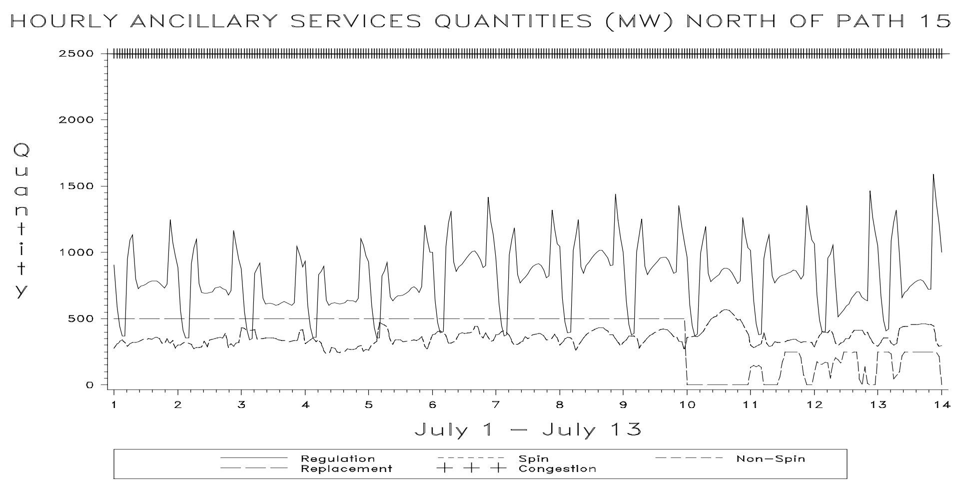

HOURLY ANCILLARY SERVICES PRICES ($/MW) SOUTH OF PATH 15
Price
300
250
200
150
100
50
0
13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
July 13 — July 31
Regulation
Spin
Non-Spin
Replacement
Congestion

Figure 3


HOURLY ANCILLARY SERVICES QUANTITIES (MW) NORTH OF PATH 15
Quantity
June 1 — June 30
Regulation
Spin
Non-Spin
Replacement
Congestion


HOURLY ANCILLARY SERVICES QUANTITIES (MW) NORTH OF PATH 15
Quantity
July 1 — July 13
Regulation
Spin
Non-Spin
Replacement
Congestion

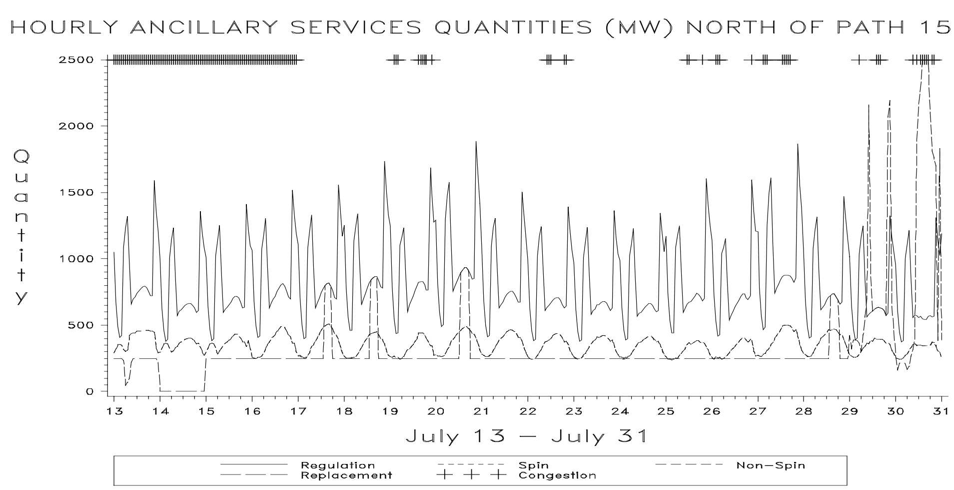
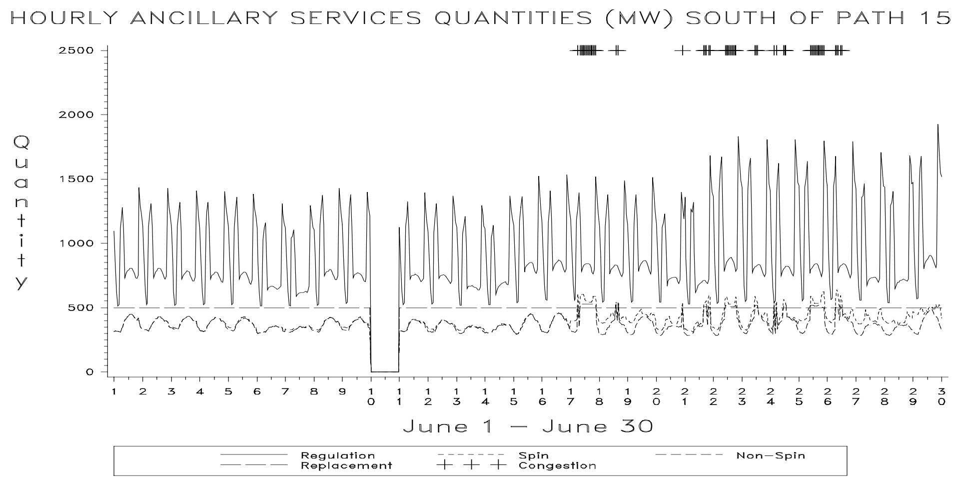
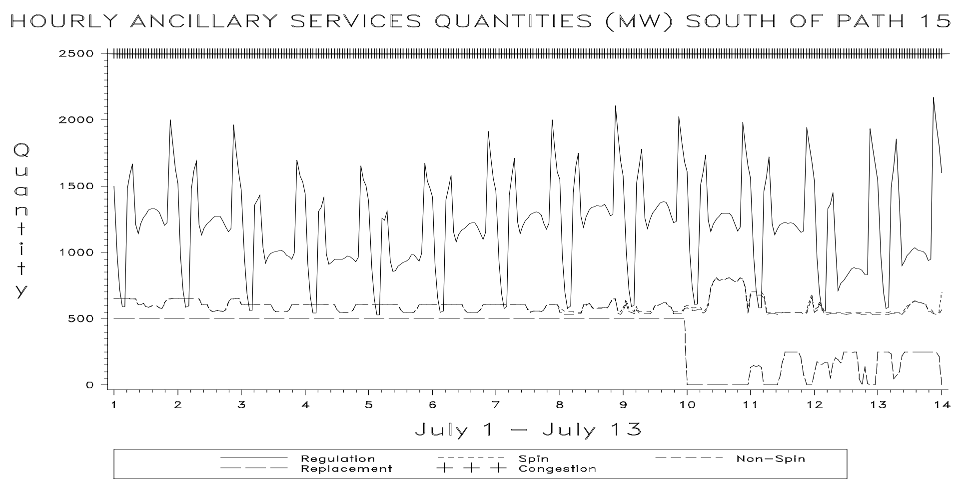

HOURLY ANCILLARY SERVICES QUANTITIES (MW) NORTH OF PATH 15
Quantity
July 13 — July 31
Regulation
Spin
Non-Spin
Replacement
Congestion

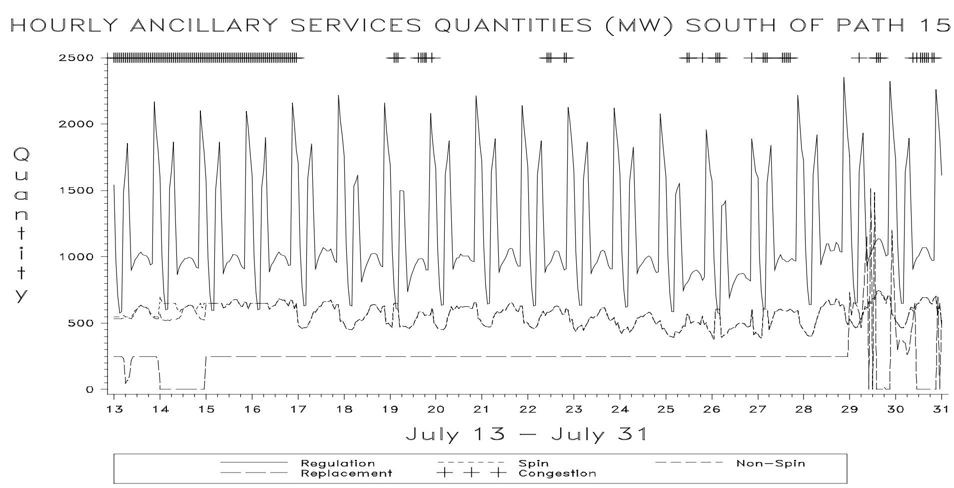
Figure 4



HOURLY ANCILLARY SERVICES QUANTITIES (MW) SOUTH OF PATH 15
Quantity
June 1 — June 30
Regulation
Replacement
Spin
Congestion
Non-Spin

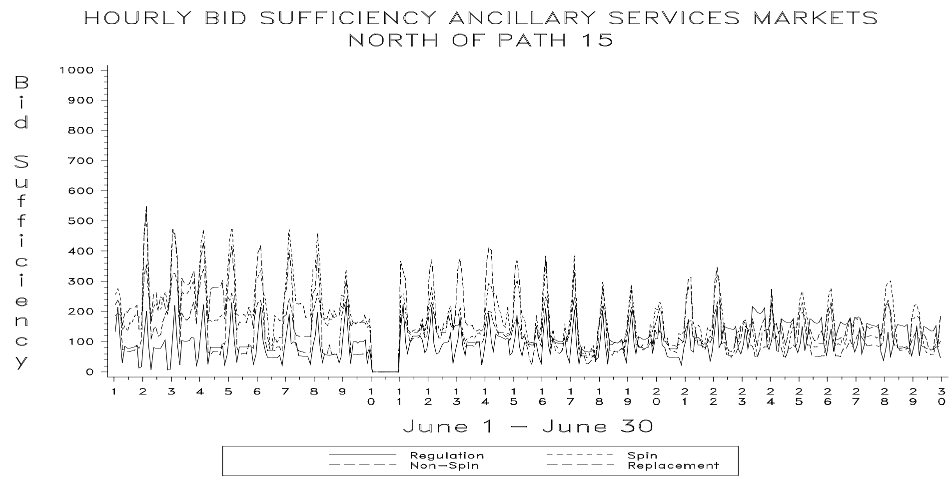


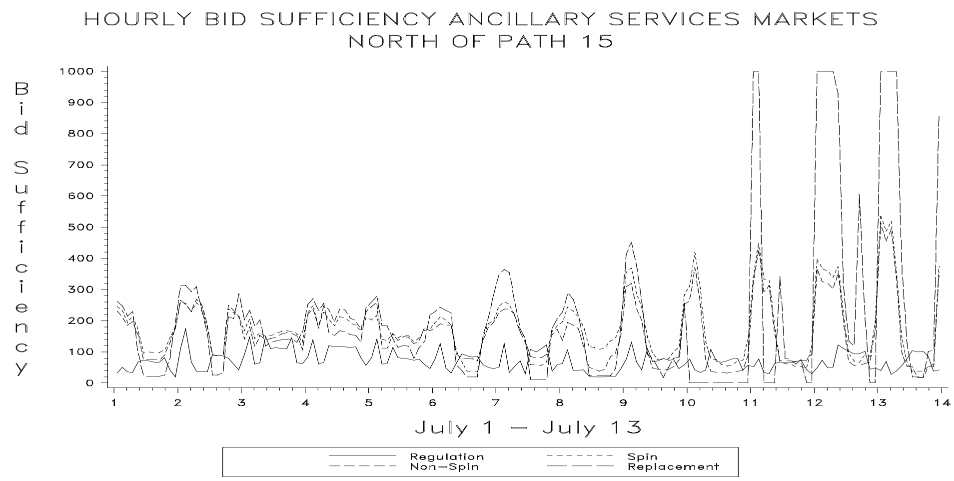
HOURLY ANCILLARY SERVICES QUANTITIES (MW) SOUTH OF PATH 15
Quantity
July 1 — July 13
Regulation
Replacement
Spin
Congestion
Non-Spin



HOURLY ANCILLARY SERVICES QUANTITIES (MW) SOUTH OF PATH 15
Quantity
July 13 — July 31
Regulation
Replacement
Spin
Congestion
Non-Spin

Figure 5


HOURLY BID SUFFICIENCY ANCILLARY SERVICES MARKETS
NORTH OF PATH 15
Bid Sufficiency
June 1 — June 30
Regulation
Spin
Non-Spin
Replacement


HOURLY BID SUFFICIENCY ANCILLARY SERVICES MARKETS
NORTH OF PATH 15
Bid Sufficiency
July 1 — July 13
Regulation
Spin
Non-Spin
Replacement

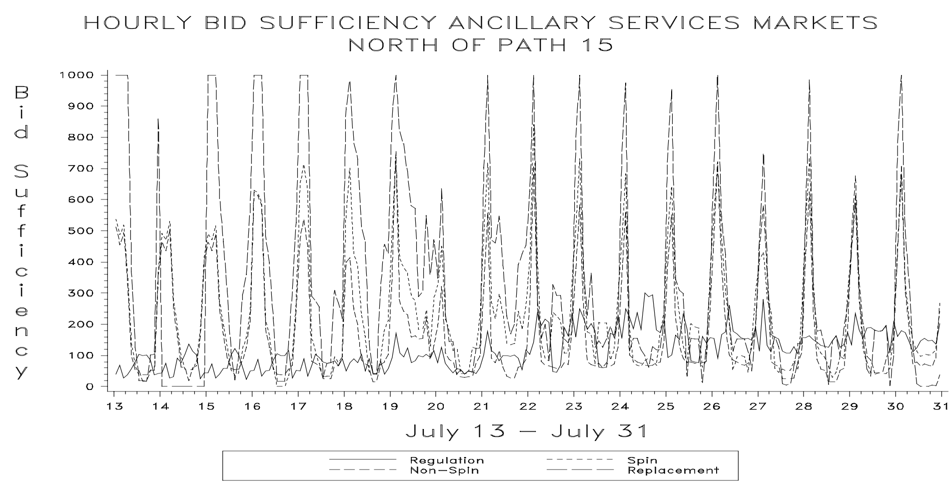
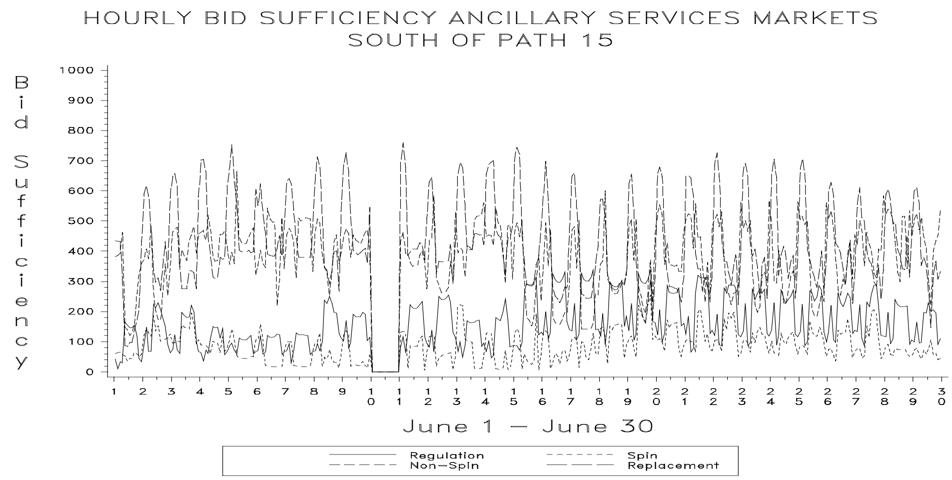
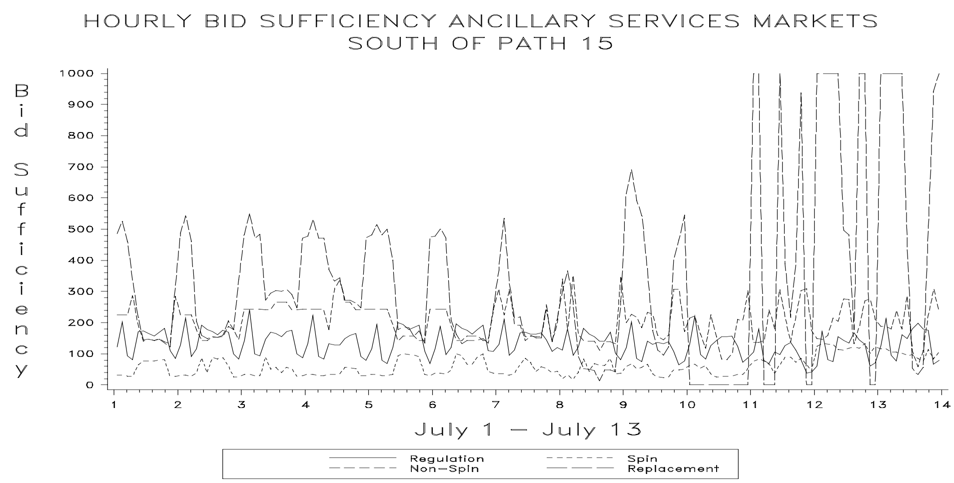

HOURLY BID SUFFICIENCY ANCILLARY SERVICES MARKETS
NORTH OF PATH 15
Bid Sufficiency
July 13 — July 31
Regulation
Spin
Non-Spin
Replacement

Figure 6


HOURLY BID SUFFICIENCY ANCILLARY SERVICES MARKETS
SOUTH OF PATH 15
Bid Sufficiency
June 1 — June 30
Regulation
Spin
Non-Spin
Replacement


HOURLY BID SUFFICIENCY ANCILLARY SERVICES MARKETS
SOUTH OF PATH 15
Bid Sufficiency
July 1 — July 13
Regulation
Spin
Non-Spin
Replacement

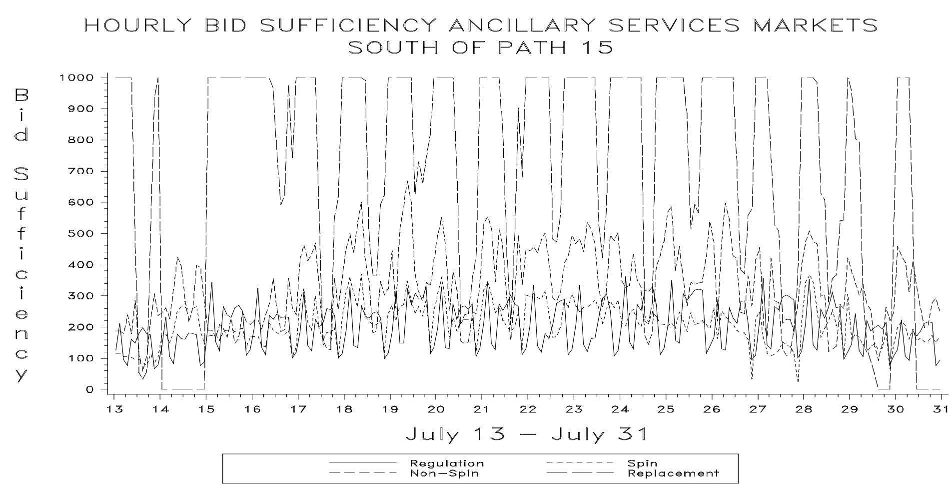
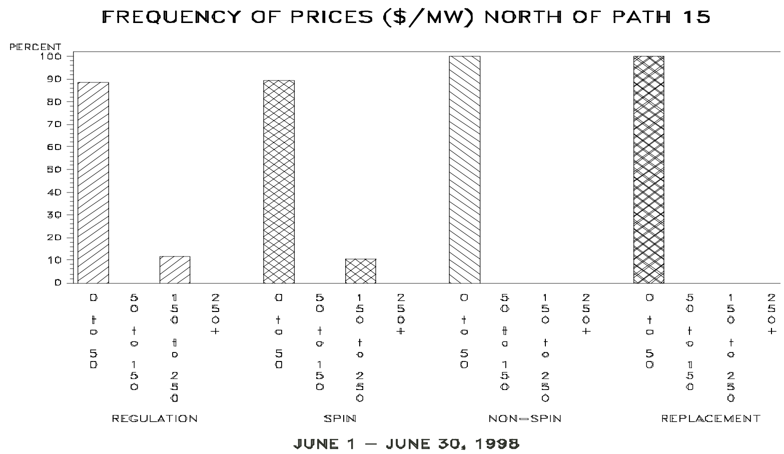
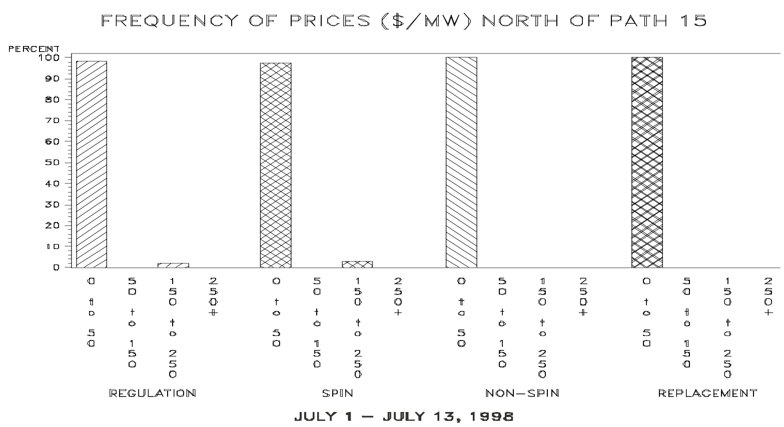

HOURLY BID SUFFICIENCY ANCILLARY SERVICES MARKETS
SOUTH OF PATH 15
Bid Sufficiency
July 13 — July 31
Regulation
Spin
Non-Spin
Replacement

Figure 7


FREQUENCY OF PRICES ($/MW) NORTH OF PATH 15
PERCENT
100
90
80
70
60
50
40
30
20
10
0
0 to 50
50 to 150
150 to 250
250+
REGULATION
SPIN
NON-SPIN
REPLACEMENT
JUNE 1 — JUNE 30, 1998


FREQUENCY OF PRICES ($/MW) NORTH OF PATH 15
PERCENT
100
90
80
70
60
50
40
30
20
10
0
0 to 50
50 to 150
150 to 250
250+
REGULATION
SPIN
NON-SPIN
REPLACEMENT
JULY 1 — JULY 13, 1998

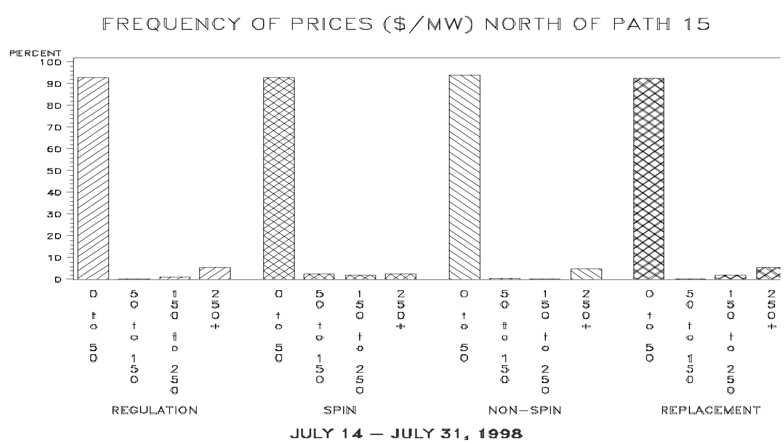
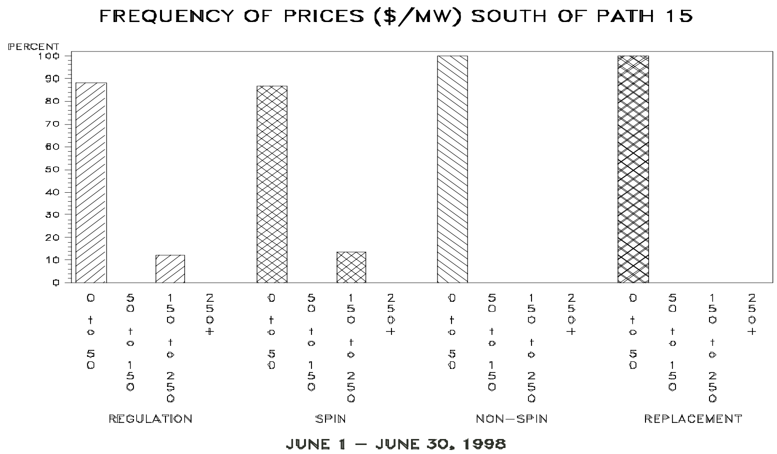
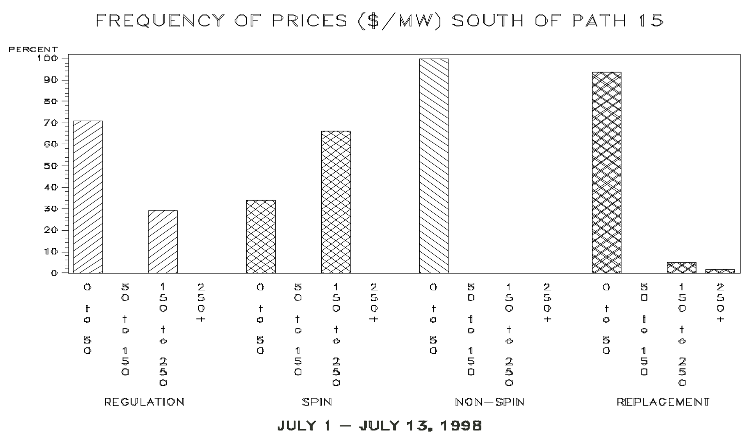

FREQUENCY OF PRICES ($/MW) NORTH OF PATH 15
PERCENT
100
90
80
70
60
50
40
30
20
10
0
0 to 50
50 to 150
150 to 250
250+
REGULATION
SPIN
NON-SPIN
REPLACEMENT
JULY 14 — JULY 31, 1998

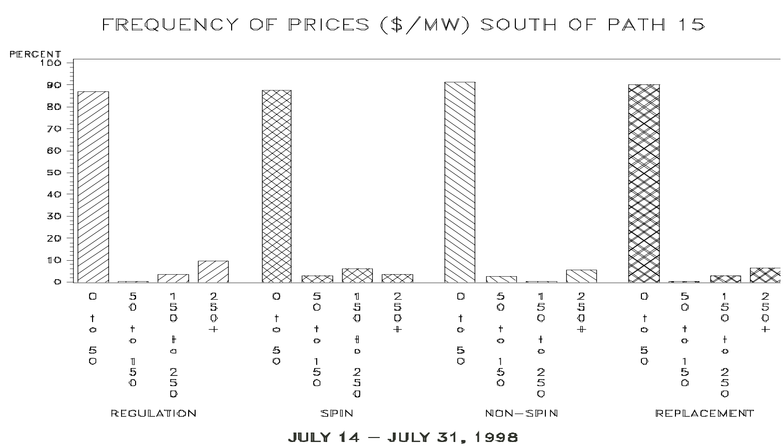
Figure 8



FREQUENCY OF PRICES ($/MW) SOUTH OF PATH 15
PERCENT
0
10
20
30
40
50
60
70
80
90
100
0 to 50
50 to 150
150 to 250
250+
REGULATION
SPIN
NON-SPIN
REPLACEMENT
JUNE 1 — JUNE 30, 1998

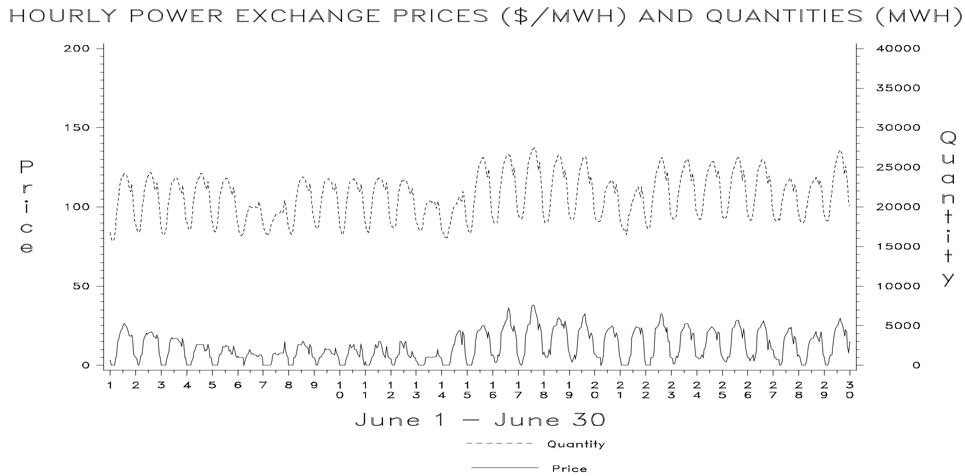


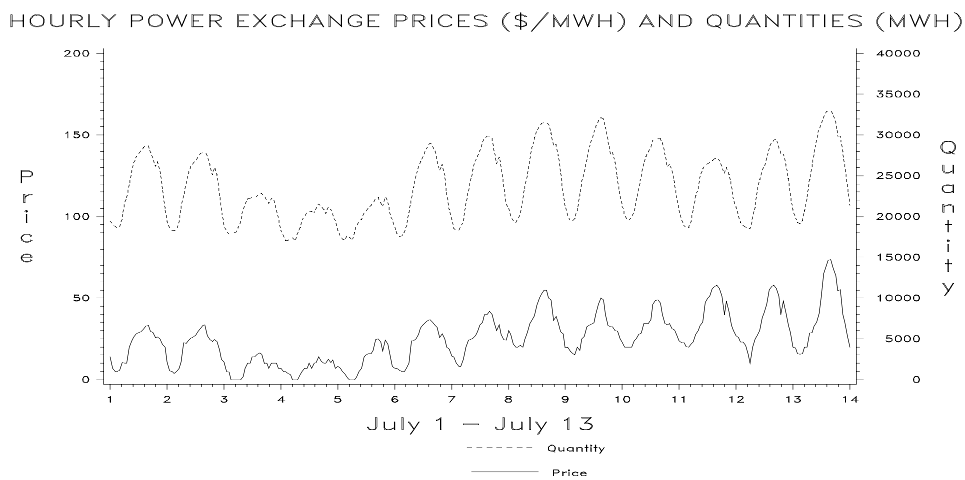
FREQUENCY OF PRICES ($/MW) SOUTH OF PATH 15
PERCENT
0
10
20
30
40
50
60
70
80
90
100
0 to 50
50 to 150
150 to 250
250+
REGULATION
SPIN
NON-SPIN
REPLACEMENT
JULY 1 — JULY 13, 1998



FREQUENCY OF PRICES ($/MW) SOUTH OF PATH 15
PERCENT
0
10
20
30
40
50
60
70
80
90
100
0 to 50
50 to 150
150 to 250
250+
REGULATION
SPIN
NON-SPIN
REPLACEMENT
JULY 14 — JULY 31, 1998

Figure 9


HOURLY POWER EXCHANGE PRICES ($/MWH) AND QUANTITIES (MWH)
Price
Quantity
June 1 — June 30
Quantity
Price


HOURLY POWER EXCHANGE PRICES ($/MWH) AND QUANTITIES (MWH)
Price
Quantity
July 1 — July 13
Quantity
Price

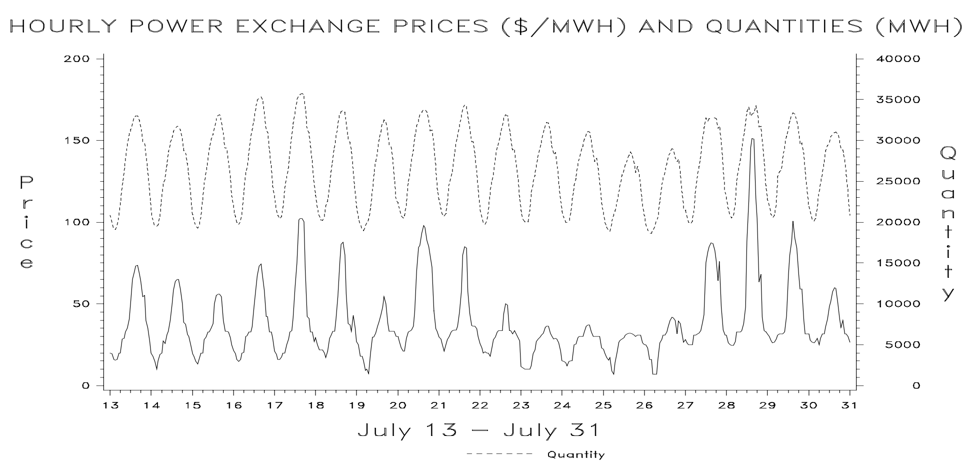

HOURLY POWER EXCHANGE PRICES ($/MWH) AND QUANTITIES (MWH)
Price
Quantity
July 13 — July 31
Quantity
Price

Figure 10

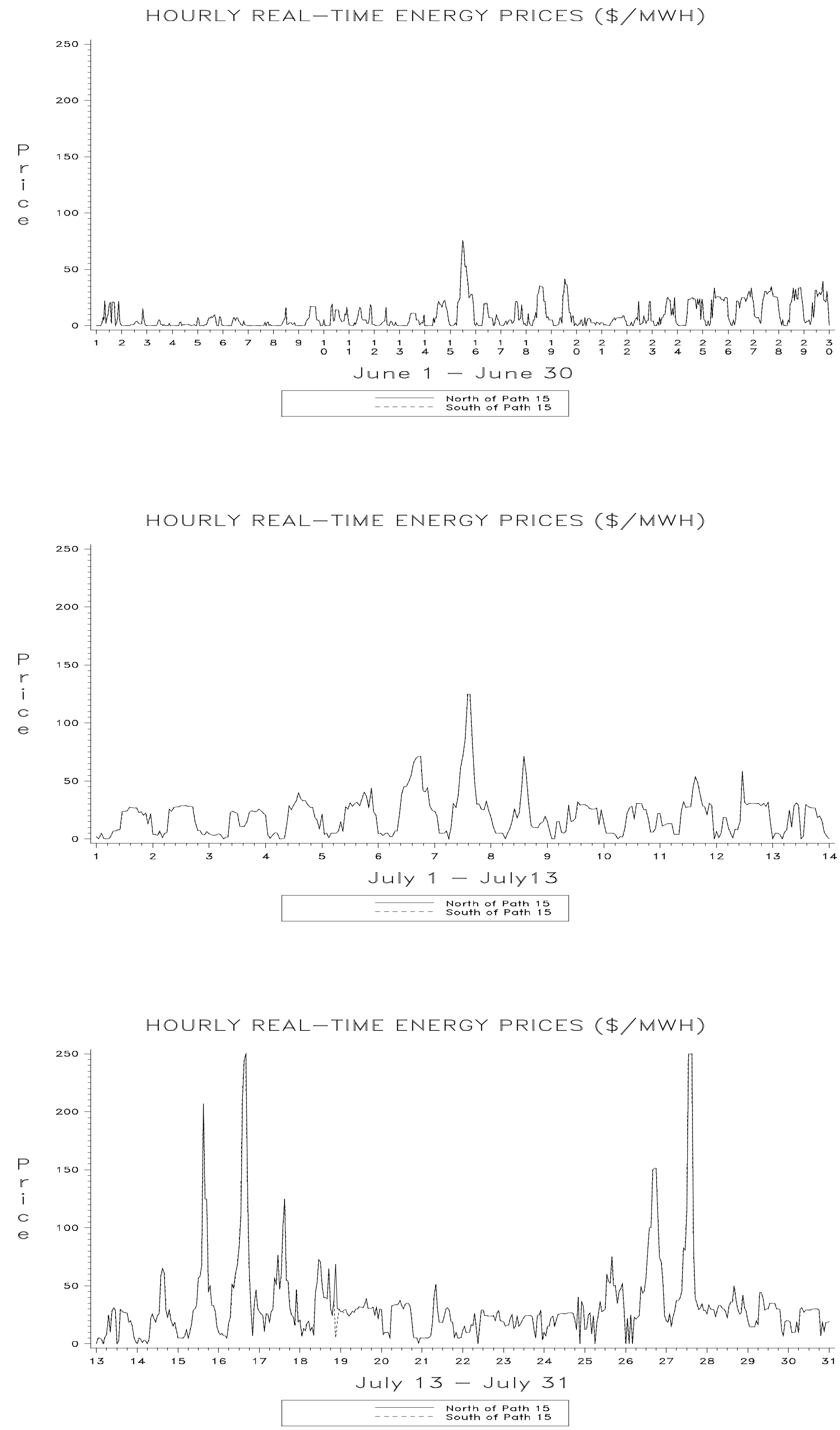
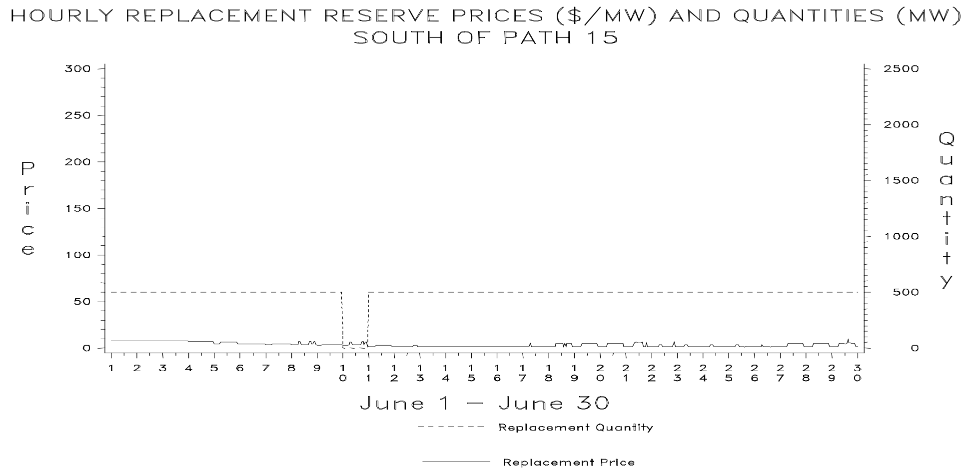
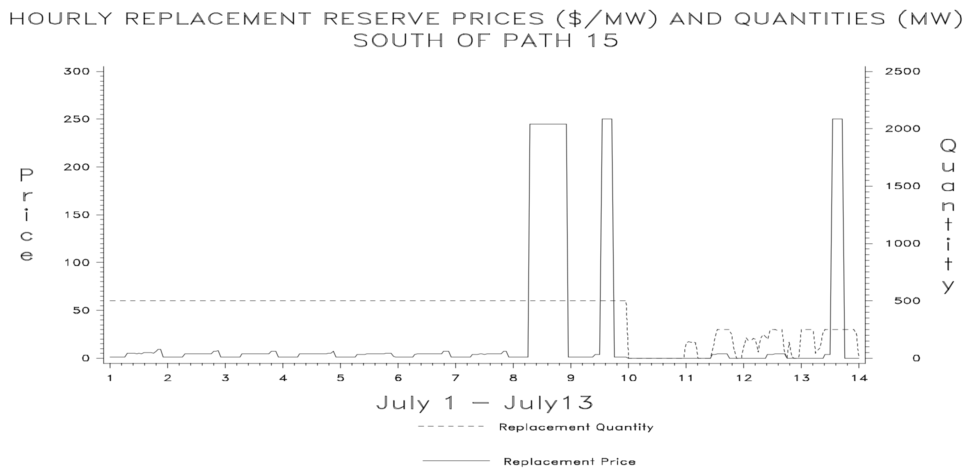

HOURLY REAL–TIME ENERGY PRICES ($/MWH)
Price
June 1 – June 30
North of Path 15
South of Path 15
HOURLY REAL–TIME ENERGY PRICES ($/MWH)
Price
July 1 – July13
North of Path 15
South of Path 15
HOURLY REAL–TIME ENERGY PRICES ($/MWH)
Price
July 13 – July 31
North of Path 15
South of Path 15

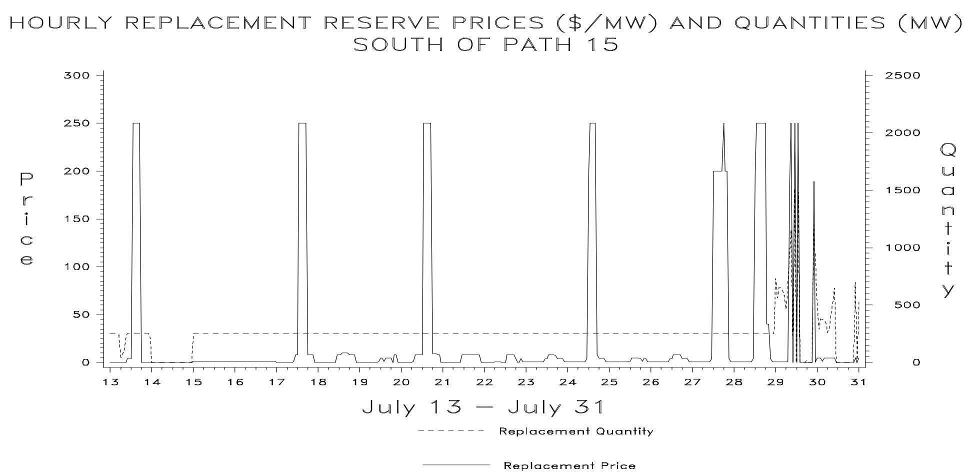
Figure 11



HOURLY REPLACEMENT RESERVE PRICES ($/MW) AND QUANTITIES (MW)
SOUTH OF PATH 15
Price
Quantity
June 1 — June 30
Replacement Quantity
Replacement Price

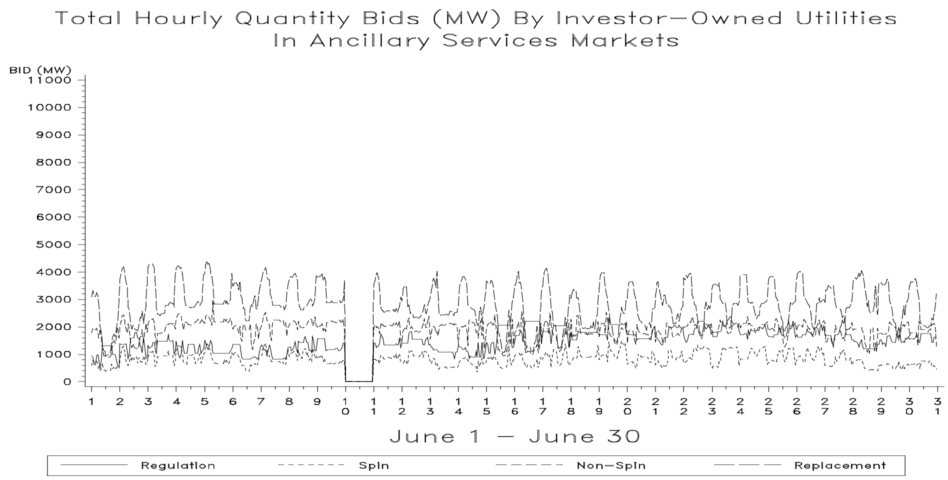


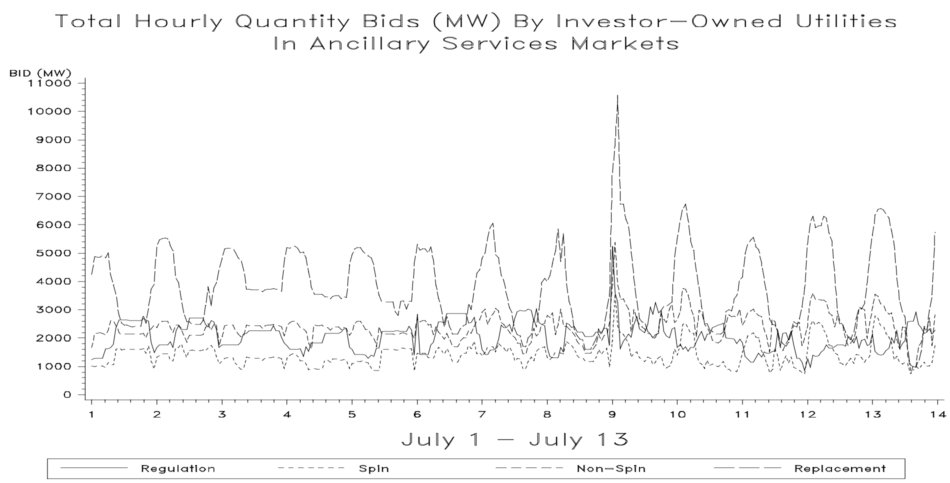
HOURLY REPLACEMENT RESERVE PRICES ($/MW) AND QUANTITIES (MW)
SOUTH OF PATH 15
Price
Quantity
July 1 — July13
Replacement Quantity
Replacement Price



HOURLY REPLACEMENT RESERVE PRICES ($/MW) AND QUANTITIES (MW)
SOUTH OF PATH 15
Price
Quantity
July 13 — July 31
Replacement Quantity
Replacement Price

Figure 12


Total Hourly Quantity Bids (MW) By Investor-Owned Utilities
In Ancillary Services Markets
BID (MW)
June 1 - June 30
Regulation
Spin
Non-Spin
Replacement


Total Hourly Quantity Bids (MW) By Investor-Owned Utilities
In Ancillary Services Markets
BID (MW)
July 1 - July 13
Regulation
Spin
Non-Spin
Replacement

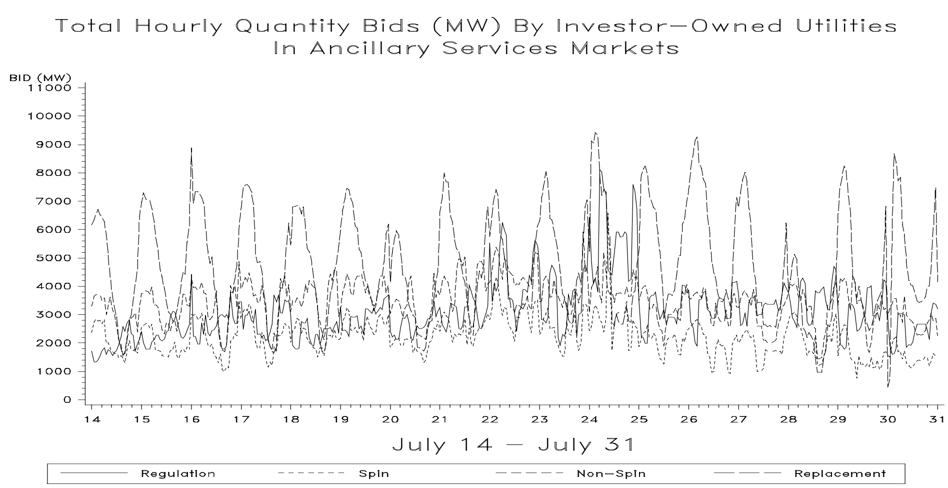
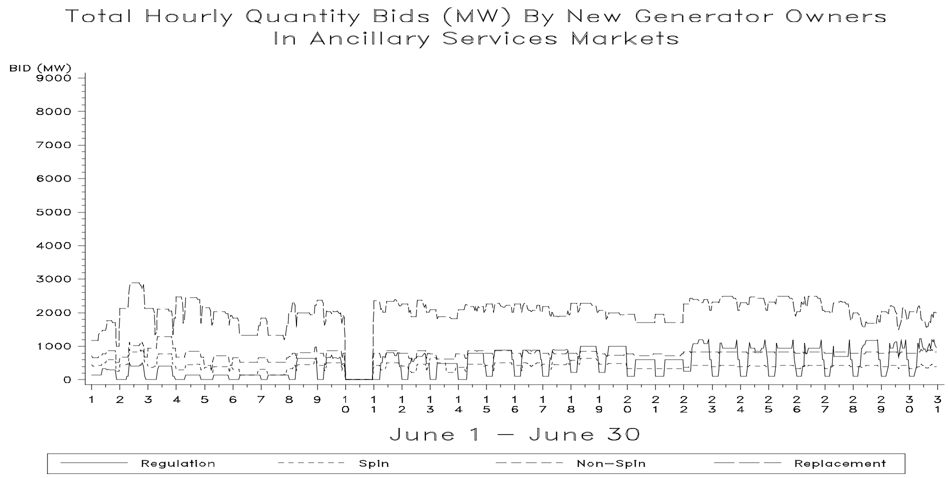
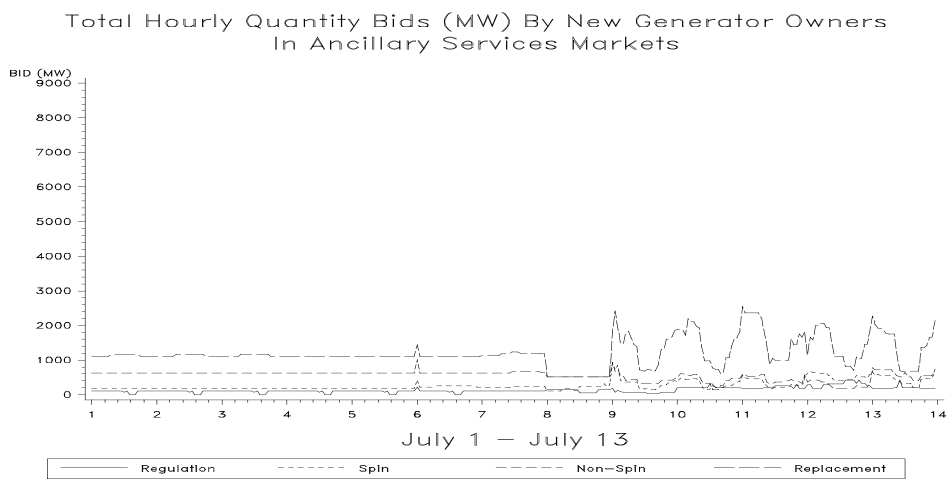

Total Hourly Quantity Bids (MW) By Investor-Owned Utilities
In Ancillary Services Markets
BID (MW)
July 14 - July 31
Regulation
Spin
Non-Spin
Replacement

Figure 13


Total Hourly Quantity Bids (MW) By New Generator Owners
In Ancillary Services Markets
BID (MW)
June 1 – June 30
Regulation
Spin
Non-Spin
Replacement


Total Hourly Quantity Bids (MW) By New Generator Owners
In Ancillary Services Markets
BID (MW)
July 1 – July 13
Regulation
Spin
Non-Spin
Replacement

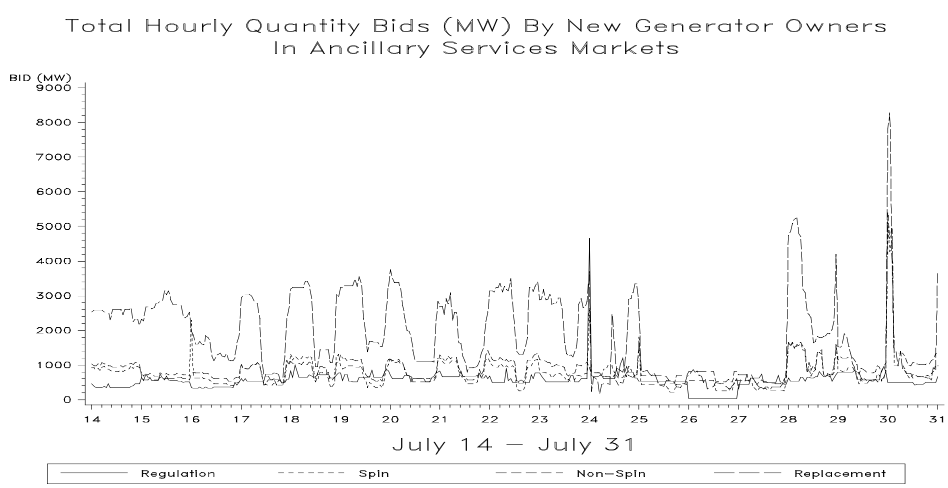
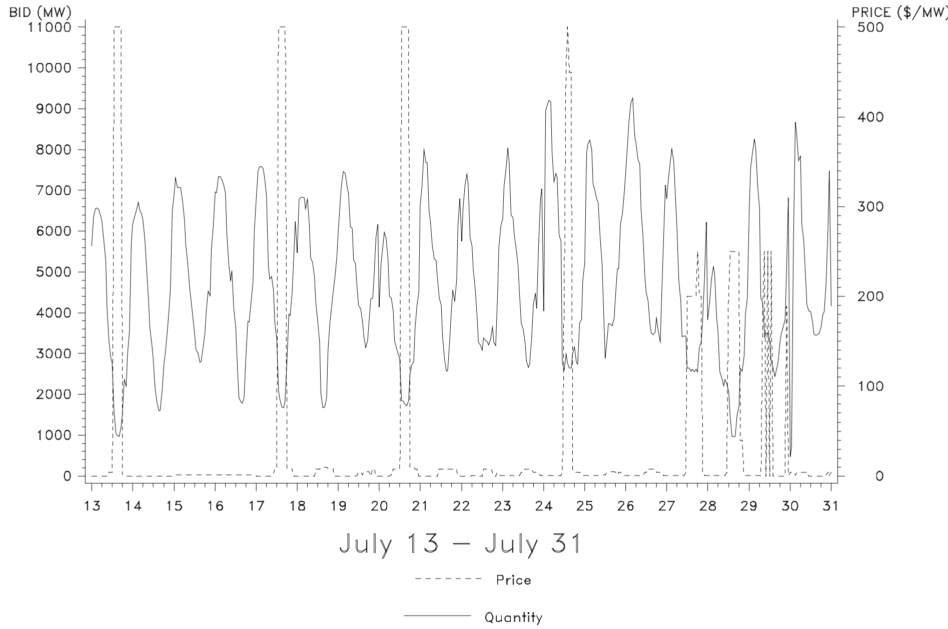

Total Hourly Quantity Bids (MW) By New Generator Owners
In Ancillary Services Markets
BID (MW)
July 14 – July 31
Regulation
Spin
Non-Spin
Replacement

Figure 14

Total Hourly Quantity Bid (MW) By Investor–Owned Utilities
And Price ($/MW) in Replacement Reserve Market South of Path 15



Total Hourly Quantity Bid (MW) By New Generator Owners
And Price ($/MW) in Replacement Reserve Market South of Path 15

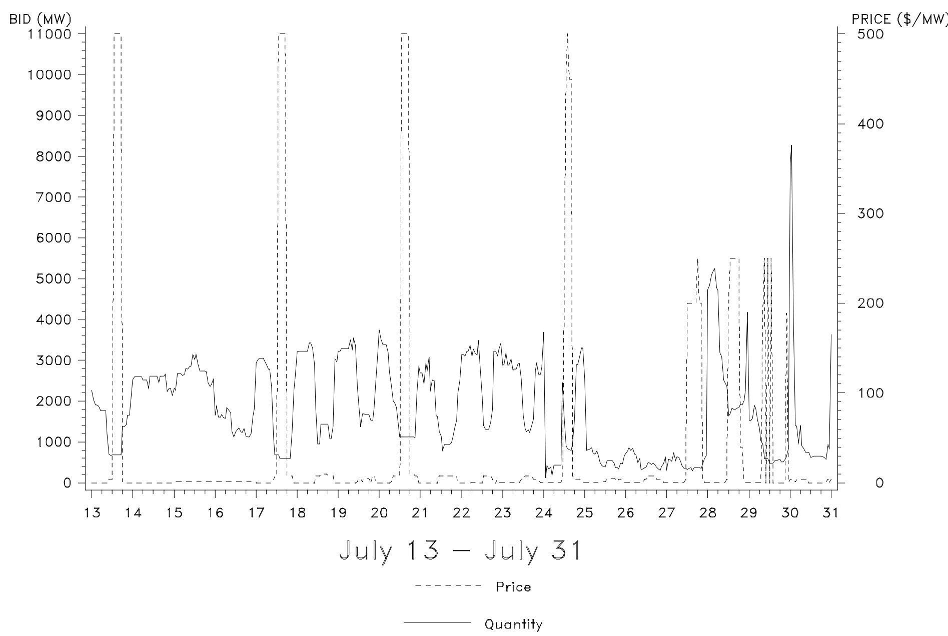
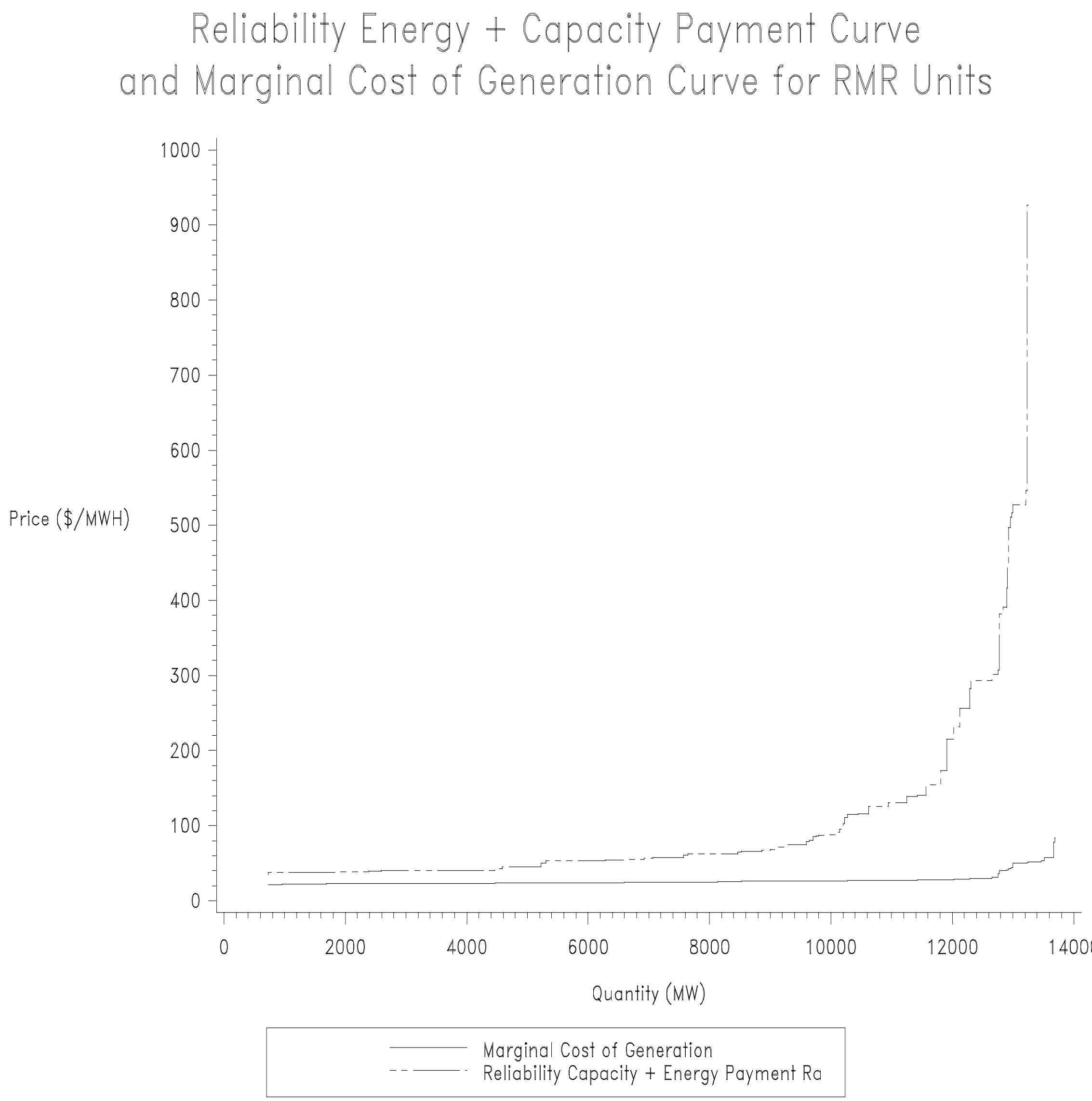


Figure 15



Reliability Energy + Capacity Payment Curve
and Marginal Cost of Generation Curve for RMR Units
Price ($/MWH)
1000
900
800
700
600
500
400
300
200
100
0
0
2000
4000
6000
8000
10000
12000
14000
Quantity (MW)
Marginal Cost of Generation
Reliability Capacity + Energy Payment Ra

Figure 16: Schedule Imbalances Over Time