UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company
Complainant,
v. Docket No. EL00-95-012

Sellers of Energy and Ancillary Services
Into Markets Operated by the California
Independent System Operator and the
California Power Exchange,
Respondents.

NOTICE OF OPPORTUNITY FOR COMMENT ON
STAFF RECOMMENDATION ON PROSPECTIVE MARKET MONITORING
AND MITIGATION FOR THE CALIFORNIA WHOLESALE ELECTRIC MARKET

(March 9, 2001)

Take notice that the Commission staff has prepared a recommendation for prospective market monitoring and mitigation for the California wholesale electric market. The recommendations are those of the staff of the Federal Energy Regulatory Commission and do not necessarily reflect the views of the Commission or any of its Commissioners. Parties in this proceeding may file comments on the staff recommendation by March 22, 2001. Documents previously filed in Docket No. EL00-95-000, et al., need not be refiled in this sub-docket and no additional petitions for intervention are required for parties in Docket No. EL00-95-000, et al., to participate in this sub-docket.

Copies of this document are available for public inspection in the Public Reference Room of the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, D.C., 20426. This document may be viewed on the web at http://www.ferc.fed.us/online/rims.htm or http://www.ferc.fed.us/electric/bulkpower.htm (call 202-208-2222 for assistance). Comments may be filed electronically via the internet in lieu of paper. See 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's web site at http://www.ferc.fed.us/efi/doorbell.htm.

David P. Boergers
Secretary

United States of America
Federal Energy Regulatory Commission

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STAFF RECOMMENDATION ON PROSPECTIVE MARKET MONITORING AND MITIGATION FOR THE CALIFORNIA WHOLESALE ELECTRIC POWER MARKET

March 2001

Contents

1. Overview

The Commission's December 15, 2000 order (EL00-95-000) directed, among other things, staff to convene a technical conference to review possible prospective market monitoring and mitigation approaches for the California market. It further directed staff to provide the Commission with a recommendation. The following proposal is Staff's recommendation on a market monitoring and mitigation plan to replace the $150/Mwh break point approach contained in the December 15 order.

While these recommendations are tailored to the particular shortcomings of the California market today, ultimately the <u>real</u> solution to California's problems lies in increased investments in infrastructure. California is typically a net importer of energy from other parts of the West and a certain amount of imports are to be expected in any market. However, while demand has grown dramatically in California and the West over the last ten years, virtually no new generation has been added. Similarly, the increased reliance of regions within California and the rest of the West on widely dispersed resources to provide peak needs over the past several years has revealed significant needs for transmission expansion and investment. Finally, the inability of demand to respond to higher prices has contributed to the problems in California's market. While demand response is normally thought to be an issue of design, for truly robust demand responsiveness investments in infrastructure are needed.

Staff has attempted to propose a market monitoring and mitigation approach that recognizes that scarcity conditions will exist for the near term and that, during such periods, some extraordinary measures must be considered. However, the overall approach must be consistent with the need to attract new investment and should, to the maximum extent possible, encourage such investment. Should the Commission proceed with this recommended approach, it should be recognized that the mitigation proposed is designed to apply only to approximately 5% of the market that remains in real-time and not to the bilateral and forward markets. In its December 15 order, the Commission removed the mandatory buy-sell requirement for IOUs with the California Power Exchange and, in effect, allowed the state to price the substantial amount of power (25,000 MW) produced or controlled by California IOUs. This change, as well as subsequent efforts at signing long-term bilateral contracts, has limited the size of the spot market subject to the mitigation recommendations here.

In order to mitigate significant exercises of market power during periods of scarcity, staff recommends the following measures:

- *Coordinating and Controlling Outages*. All planned outages by units which have signed a Participating Generator Agreement (PGA) with the

ISO should be coordinated with, and approved by, the ISO. Unplanned outages should be closely monitored by the ISO and questionable outages should be reported immediately to the Commission for further investigation by the Commission.

- *Selling Obligations*. Sellers with PGAs should be required to offer all their capacity to the ISO in real time if it is available and not scheduled to run. Load Serving Entities should be required to state the price at which they will curtail their loads, and to identify which loads will be curtailed.

- *Price Mitigation*. When called upon to provide available (unscheduled) capacity in real time, PGA units would be price mitigated only in those hours when there is a reserve deficiency (e.g., Stage 3.) During these hours all PGA units obligated to sell capacity in real time would be paid the marginal cost of the highest-priced PGA unit called upon to run.

- *Real-time Price Mitigation for Each Generating Unit.* Each generating unit should be required to have a standing, confidential price based on its marginal costs, to be used by the ISO to establish the real-time market clearing price when mitigation is appropriate.

- *A market clearing price.* All energy offers that are accepted in the real-time market should be paid the applicable market clearing price.

- *Conditions for Invoking Mitigation.* Application of mitigation should be restricted to critical operating periods, such as emergencies when reserves are scarce and load must be reduced.

Recognizing that every administrative solution proposed by regulators can have unintended consequences, staff also provides a possible alternative approach for the Commission to consider that relies more on constraints in the longer-term, bilateral market for a prescribed period of time while leaving the spot market unconstrained to respond to shortages. Staff also provides a summary of comments and proposals made by other parties that were solicited during and immediately following a technical conference held in January.

Regardless of the approach ultimately adopted by the Commission to mitigate prices during periods of inadequate reserves, the necessary infrastructure investments in California and the West may not be undertaken unless the Commission provides regulatory certainty for market participants. This certainty has been missing in California for the past several months. Consequently, we strongly recommend a date-certain "sunset" for the mitigation approach of no more than one year. We also recommend that mitigation levels be adjusted within the time period, if necessary, to help ensure new investments in infrastructure are undertaken quickly.

It is important to emphasize that this proposal is predicated on the unique market conditions that currently exist in California and should not be viewed as applicable to any other region or time period. California has suffered multiple shocks, including the consequences felt from over reliance on short-term markets, widening scarcity of resources, depleted hydro resources, extreme load conditions and a rate freeze that has stymied demand response to high prices. Generally, any market that has a surplus of supply options and some degree of demand response will not require such intrusive mitigation measures and the function of market monitoring should be much more limited. However, staff recommends that the Commission consider, on a short-term basis, some measure of mitigation for California markets while also encouraging infrastructure investment and price-responsive demand.

The report is organized as follows. Section 2 describes the scope of the task covered by the staff proposal under the provisions of the December 15 order. Section 3 provides a summary of the themes from comments filed with staff. Section 4 presents an overview of the principles of market monitoring and mitigation, as well as common mechanisms for applying principles. Section 5 contains the staff proposal for monitoring and mitigation, followed by a brief description of alternatives considered in Section 6.

2. The Scope of the Task

The Federal Energy Regulatory Commission issued an order on December 15, 2001, in Docket No. EL00-95-000, et al.[1] that required a number of short- and long-term changes to the structure of the California wholesale electric market, and that also instituted an interim market monitoring and mitigation program to be in effect from January 1, 2001, until replaced by another plan to take effect around May 1, 2001. The December 15 order also required that the Director of the Division of Energy Markets in the Office of Markets, Tariffs and Rates convene a technical conference not later than January 25, 2001. The technical conference was held on January 23, 2001, and comments and reply comments were filed with the Commission and posted on its web site. In the order the Commission also directed staff to submit to the Commission a proposal to replace the interim market monitoring and mitigation program.

In the November 1 and December 15 orders,[2] the Commission concluded that wholesale markets operated by the California ISO and PX could result in wholesale electric rates that were unjust and unreasonable under certain circumstances. The December 15 order contained several provisions that were intended to address the structure of those markets. Specifically, the order:

- Immediately abolished the requirement in the PX wholesale tariff that California investor owned utilities (IOUs) bid all of their capacity into and purchase all of their power through the PX.

- Required that as of January 1, 2001, all bids submitted to the CalPX in its day of and day ahead markets and the ISO in its real-time markets for less than $150 per megawatt hour be used to set a price under a single price market clearing price auction methodology, and that all bids over $150 per megawatt hour be accepted at the actual bid price.

- Established certain reporting requirements for all bids above $150 per MWh submitted through the PX bidding process and the ISO real time markets by public utilities. Prices in excess of $150 per megawatt hour are

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[1]San Diego Gas & Electric Company, Complainant v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange, et al., 93 FERC ¶ 61,294 (2000).

[2] 93 FERC ¶ 61,121 (2000).

subject to refund but refund liability will be lifted and the bids covered in the report will be deemed just and reasonable absent further action by the Commission within 60 days after the filing of the report.

- Terminated the PX tariff as of the April 30, 2001 trading day.

- Required all load serving entities served by the ISO to schedule at least 95 percent of their anticipated capacity needs prior to real-time, and established penalties for failure to do so.

- Required the ISO to adopt a non-stakeholder governing board, and provided for coordinating this effort with representatives of the state of California.

- Extended, until April 1, 2001, the right of certain QFs in California to operate in excess of the amounts authorized by their regulatory licences.

- Required the three California IOU's to develop a uniform set of interconnection procedures to be filed no later than April 1, 2001.

- Required the ISO to develop, on an expedited basis, a marginal cost based method for allocating congestion costs to replace its current zonal method.

The interim market monitoring provisions established by the December 15 order consist of the $150 breakpoint differentiating the type of auction to be used, and the related refund and reporting provisions. The related reporting requirements provide that all wholesale electric prices in noted PX and ISO markets are to be reported to the Commission on a weekly (by public utility sellers) and monthly (by the PX and ISO) basis. The seller reports must contain detailed information on the parties involved in the transaction, its time frame, the estimated costs of the seller, and apply to each hour in a 24-hour period.

The December 15 order contemplated that the breakpoint method would discipline prices in California in the interim until a more comprehensive market monitoring method could be adopted by the Commission around May 1, 2001. The December 15 order explicitly states that the breakpoint methodology is expected to be superseded on that date but does not state whether the related reporting requirements and the refund obligation will also be superseded on May 1, 2001. However, it is logical for these specific reporting and refund requirements associated with the $150 breakpoint to be superceded on the same date, if the replacement mitigation adopted by the Commission is sufficient to ensure just and reasonable rates. The Staff recommendations in this report assume that all other requirements in the December 15 order will remain in effect after the Commission adopts longer term market monitoring and mitigation methods around May 1, 2001.

The structure of the California wholesale electric market is very unsettled at this time. The CalPX suspended trading on January 31, 2001. It is now functioning only as a financial clearing house and a scheduling entity. While no firm date has been established, the CalPX is expected to terminate its operations in the near future, and it is possible that some aspects of its operations will migrate to the CalISO. The immediate consequence of cessation of trading operations by the CalPX is that most transactions in the California wholesale electric market are bilateral transactions. However, it appears that most bilateral contracts continue to be short term in nature and there has been only limited hedging of risks for consumers via longer term contracts. The credit problems of the California IOUs have caused considerable disruption to the wholesale power market; the state of California, through the California Department of Water Resources, has entered the market, at least for certain bilateral transactions, to provide a creditworthy buyer.

Based on the directives of the December 15 order and the shrinking markets operated by the CalISO and PX, the central issue addressed by staff is the market power that may exist during the bidding processes required to purchase wholesale electricity in the real time market. The December 15 order returned control and pricing of 25,000 megawatts of capacity to California, substantially increasing California's ability to control pricing for the retail market and markets other than the real time wholesale market. In addition, the state of California, through the Department of Water Resources, is actively involved in longer-term bi-lateral markets on behalf of loads. In light of these factors, it is appropriate for this staff recommendation to focus on real-time markets. However, the more fundamental structural elements in the California wholesale markets remain important and should be addressed at a separate technical conference with opportunity for public input, perhaps using the detailed market structure proposal recently submitted by the CalISO as a starting point.

3. Summary of Proposals in the Comments

Following the January 23 technical conference, parties filed comments and reply comments in their recommendations. These comments contain a range of general proposals and specific measures. A detailed summary of the filed comments, by commenter, is provided in the Appendix. The general themes raised regarding measures to monitor and mitigate market power are summarized below.

Forward Contracting Requirement

Both the ISO and the ISO's Market Surveillance Committee (MSC) would require all generators and marketers within California to offer forward contracts for much (e.g., 70 percent) of their capacity at a cost-based price. The ISO MSC argues that forward contracting reduces or eliminates a seller's incentive to exercise market power in the real-time market. Under the ISO's proposal, suppliers that fail to meet the 70-percent forward contract requirement would be subject to cost-based rates for all sales in California. The forward contracting requirement is supported by the County of San Diego and the CPUC. It is opposed by a coalition of generators (Mirant et al.)[3] and the Electric Power Supply Association (EPSA). The California Department of Water Resources (DWR) argues that it needs flexibility in making forward contracting decisions, including all terms and contract periods. It urges the Commission not to impede DWR's efforts to acquire power through forward markets.

Available Capacity Reserve (ACR) Requirement

The ISO proposes that load serving entities (LSEs) must contract for resources equal to 115 percent of their annual peak load. ACR, proposed by the ISO, is similar to the Installed Capacity Requirement in existence in other parts of the country. In exchange for receiving annual capacity payments, the resources supplying ACR capacity would guarantee that their capacity would be available to the market and would deliver energy or reserve service if dispatched. The proposal is supported by the County of San Diego. It is opposed by Strategic Energy, who argues that developers should be allowed to respond to free-market signals.

Bidding Requirement and Capacity Availability Standards

[3]Mirant-Reliant-Duke-Dynegy-Williams.

The ISO's MSC recommends imposing a capacity availability standard on all market participants located in California – a mechanism similar in many respects to ACR. Under the MSC's proposal, all generators would be required to submit annual planned outage schedules, and they would be required to submit standing bids (at whatever prices they choose) into the real-time energy market for all capacity not scheduled in the forward markets. If a unit does not respond to a real-time instruction by the ISO to produce, the unit would be required to buy the amount of energy in the real-time market. The MSC's mechanism is intended to reduce market power by penalizing physical withholding. Unlike the ACR requirement, the MSC's availability standard would be mandated for all resources in California, and resources would not receive capacity payments from LSEs in exchange for making their capacity available. The Oversight Board also recommends availability standards. On the other hand, Mirant et al. oppose requiring suppliers to schedule or bid into the California markets except as agreed upon by contract or through voluntary participation in an Installed Capacity market.

Real-time Bid Caps

The ISO and TURN/UCAN recommend imposing cost-based bid caps on generators bidding into the ISO's real-time market, while allowing all accepted bids to be paid the applicable market-clearing price. The ISO recommends setting the cap for a given resource at its variable cost plus a fixed margin. TURN/UCAN argue that a bid cap reflecting incremental costs promotes competitive behavior because generators in a competitive market would bid to reflect their incremental costs. The County of San Diego supports the proposal to cap real-time bids at variable cost, but opposes adding a fixed margin to the variable-cost bid cap. On the other hand, the ISO's MSC proposes to eliminate all real-time bid caps and price caps for any generator or marketer that meets its proposed forward contracting requirement (discussed above). The MSC argues that real-time bid and price caps are unnecessary for sellers that meet its proposed forward contracting requirement, because forward contracting reduces or eliminates the incentive for the seller to exercise market power in the real time market. Mirant et al. argues that competitive firms may bid above their marginal costs to reflect such factors as opportunity costs and scarcity value.

Price Caps

Price caps are supported as a temporary measure by Mirant et al. Mirant el al. argue that the cap could be either a "soft" cap that escalates over time, or a high "circuit breaker" hard cap. Mirant argues that a temporary hard cap may be appropriate for the California market, but that the Commission should establish a definite expiration date for the cap, in order to encourage the development of demand-side management programs and to maintain a strong commitment to increasing supply.

The Role of a Market Monitoring Unit (MMU)

Mirant et al. argues that monitoring should be undertaken by a completely independent entity, and that the MMU shouldn't be part of the ISO until the ISO is independent and includes out-of-state representation. Mirant et al. and EPSA argue that the MMU should not impose sanctions or penalties, and should not adjust bids or prices. Instead, the MMU should monitor for market power and market design flaws, and should make recommendations for action to the appropriate government agency, such as the Commission or the Department of Justice. The Public Service Enterprise Group also recommends that the MMU be prohibited from changing prices retroactively, and that it instead propose changes to correct flaws in market structure and rules. The Oversight Board states that regardless of the monitoring activities undertaken by the MMU, federal and state agencies must be able to perform monitoring independently of the MMU.

Other Proposals

NCPA states that congestion management should be a primary focus of efforts to control market power. It also recommends that the ISO disclose bid information on a next-day basis (rather than after a 6-month delay) to allow third parties to detect market power more quickly. Grid Services recommends that the ISO expand the types of energy products that it purchases. The ISO currently purchases only a 10-minute product, so that generators may be called upon to produce at a given output level for only 10 minutes. Grid Services recommends that the ISO also purchase hourly or multi-hour products, which could reduce market power by expanding the supply choices available to the ISO.

4. Objectives of Market Power Mitigation

Competitive markets are widely, and rightly, regarded as powerful tools for achieving the Commission's goal of just and reasonable rates in wholesale sales of electricity. Competitive prices ensure that all power that can be delivered at a cost below the market price is provided to the market, and that all buyers who value the power above the market price are able to obtain it. The presence of significant market power can thwart the workings of these markets, by causing prices to be significantly above competitive levels. By detecting significant market power and limiting its exercise, market monitoring and market power mitigation can be an important part of harnessing the ability of competitive markets to achieve these goals. However, much care needs to be taken to ensure that mitigation measures do not inhibit the very markets they aim to protect. For example, a mitigation measure that adjusts prices retroactively can have a greater adverse and lasting impact on the market than the market power it may seek to prevent.

Market power is traditionally defined as the ability of one or more suppliers to raise the market price above the competitive level, with significant market power being the ability to sustain a substantial price increase for a significant period of time. However, the mere existence of market power does not imply that mitigation is necessary or desirable. In the real world, no market is completely free of market power at all times, and this is certainly true of wholesale electricity markets. Given that market power mitigation entails a cost, some exercise of market power may have to be tolerated, because the cost to mitigate it entirely would inevitably exceed the benefits gained. As a practical matter, judgment must be used to determine when the exercise of market power is significant enough to warrant regulatory intervention. For example, the Department of Justice (DOJ) and the Federal Trade Commission (FTC) have developed merger analysis guidelines in which they define "significant" market power in quantitative terms.

How Market Power Can Be Exercised in Electricity Markets

In wholesale electricity markets, suppliers with market power may exercise it by withholding generating capacity from the market. Withholding is profitable if it raises the market price enough to cause the revenue from capacity that is not withheld to exceed the revenue lost on the capacity that is withheld. Withholding can be either physical or economic.

With physical withholding, a supplier simply elects not to operate one or more generating units, or it may declare that a unit has suffered a forced outage when it has not. The supplier might also withhold capacity by not bringing a unit back on line as quickly as possible after it has suffered a legitimate outage. With economic withholding, a supplier makes available all of its generating capacity but offers some or all of it at a price that exceeds the marginal cost of production or other relevant opportunity cost. If these high priced units are not chosen to operate in the final dispatch, and the resulting market price is above the units' marginal cost, then the supplier has succeeded in exercising market power. However, as noted above, market power may not be significant enough to warrant regulatory intervention to prevent all exercises of market power.

Factors that Contribute to the Exercise of Market Power

In wholesale electricity markets, several factors can affect the ability of suppliers to exercise market power. For example, the concentration and market share of the suppliers in the market directly affects the ability to exercise market power. Concentration refers to the number and relative size of suppliers in the market. The smaller the number, the greater the likelihood that conditions will exist, at least occasionally, that will allow one or more suppliers to devise profitable withholding strategies. Market share refers to the fraction of the total market demand that a supplier serves with the generating capacity that it owns. A supplier with a large market share obviously has a greater ability to influence the market price by withholding capacity than a supplier with a small market share. It is important to note that the presence of transmission constraints can redefine the market so as to affect both concentration and market shares.

The ability of demand to respond to changes in price also directly affects the ability to exercise market power. Demand that is highly responsive to price changes can discipline the exercise of market power because any attempt to increase price in such an environment is more likely to reduce profits than to increase them. However, if demand cannot respond to changes in prices, which is often the case when retail rates are tightly regulated, then in periods of high demand and tight supply suppliers may be able to raise prices significantly while causing little or no decline in demand. These conditions make it possible for even small suppliers, including those in unconcentrated markets, to profit from capacity withholding strategies.

A final important factor that can affect the exercise of market power is market design and market rules. A poor market design can facilitate the exercise of market power in a number of ways. For example, if not designed properly, rules for managing congestion can facilitate the exercise of market power by generators whose strategic location allows them to benefit from the presence of transmission constraints.

Detecting the Exercise of Market Power

In principle, physical withholding can be detected by identifying instances where operable generating capacity is intentionally kept idle. However, the cost and difficulty of monitoring and investigating such behavior will likely be considerable. In addition, rarely is it possible to discover a "smoking gun" that provides conclusive evidence that capacity has been intentionally withheld. Consequently, a well designed market power mitigation plan probably should not rely solely on a program to identify and sanction instances of intentional withholding as the tool for preventing the exercise of market power.

Similarly, in principle, economic withholding can be detected by comparing the bids offered by owners of generating units with the marginal production cost and marginal opportunity costs of the units. Bids that are significantly above these cost levels could be an indication that the owners are attempting to exercise market power. However, there are a number of reasons why bids above marginal cost are not necessarily evidence of market power. For example, in forward markets (e.g., day-ahead) an owner may submit a bid that reflects a unit's opportunity cost, measured as the foregone revenue from other markets in which the owner could have participated. If, however, the owner is bidding in a real-time market, opportunities to sell in other markets generally no longer exist. Thus, with certain important exceptions, bids in real-time energy markets that are above marginal production costs may indicate attempts to exercise market power. Exceptions include the bids of energy limited units, such as hydroelectric plants and units with strict limits on emissions. Because the amount of energy that these units can produce is strictly limited by factors other than physical capacity, their owners will rationally want to operate when market prices are at their highest. Thus, if prices are expected to be low in today's real-time market, the owner may choose not to bid today and instead wait until a day when prices are expected to be higher. In addition, certain market rules may cause owners to bid in excess of marginal production costs in real-time markets. For example, a rule that specifies that a generator will be paid only for energy produced, with no separate payment for what may be significant start-up or no-load costs, may result in an owner choosing not to submit a bid, or to bid a high amount, if the owner believes that it will not receive sufficient energy payments to cover these other costs.

It is important to note that the exercise of market power is typically associated with high market prices. However, care must be taken to distinguish high prices due to the exercise of market power from high prices that are due to high costs or scarcity. Generally, if generators offer all of their capacity into the market, and all of their bids are accepted, the resulting prices cannot be viewed as reflecting the exercise of market power in the traditional sense. In times of scarce supply (i.e., when demand would exceed supply at a price equal to the marginal cost of the most expensive generating unit), the competitive price will rise above marginal production costs to a level that causes demand to fall into balance with the available supply. Of course, if retail market rules prevent wholesale price signals from being passed along to end-use consumers, then such a balance may not be achieved in conditions of extreme supply scarcity. In this case, generators may have market power that would allow them to raise the market price above the competitive level that would result if demand could see, and respond to, wholesale price signals.

Mechanisms for Mitigating Market Power

Mechanisms for mitigating market power can take the form of measures to improve market structure and measures to improve market design. Structural measures for mitigating market power include generation divestiture and the removal of barriers to entry which would increase the number of suppliers. Measures to mitigate market power through market design include rules to prevent physical withholding and rules to prevent economic withholding. Each is discussed below.

Structural Measures

In the long run, increasing transmission capacity and reducing barriers to the construction of new generating capacity are the most effective ways to reduce both concentration and market shares. As a result, any market power mitigation plan for the long term should address the siting or financial barriers to entry of new generation and transmission investment. Another common remedy, available in the shorter-term when there is a need to address high market concentration, is to require the suppliers with the largest market shares to divest enough of the production capacity to transform the market into one with lower concentration and market shares. In California, however, further divestiture probably would have only limited impact on competition and would not be likely to cause prices to fall significantly below the levels that have been experienced in recent months. An alternative structural measure would be to allow demand to respond to market conditions and price.

Market Rules to Prevent Physical Withholding

Measures to prevent physical withholding in real-time markets generally include bidding and forward contracting obligations for generators, and installed capacity obligations for load serving entities. Such measures would also include rules for coordinating planned outages and for assigning the risk of unplanned outages.

Bidding Obligations. In principle, physical withholding can be prevented by requiring generation owners to offer in the real-time market all of their operable capacity that has not been sold in a forward market. However, there are two problems with such a requirement. First, as discussed above, generation owners may be able to defeat such a requirement by claiming that their operable units have suffered a forced outage when they have not. The burden is then on the market monitor and the regulator to determine if such a claim is legitimate. Second, a bidding requirement per se does not prevent economic withholding. The generation owner can still offer all capacity, but at a very high bid price. If the bid is high enough, the owner will succeed in withholding capacity through economic means.

Forward Contracting Obligations. Requiring generation owners to enter into forward contracts for a substantial portion of their generation portfolio can help to mitigate market power in real-time energy markets. For example, consider a generator with market power that holds a contract for differences with a load serving entity. Such a contract requires the generator to compensate the buyer for the difference between the real-time energy price and the contractual price when that price is lower than the real-time price, and requires the buyer to compensate the generator when the contractual price is higher. Holding this type of contract reduces the incentive of the generator to raise real-time prices because any increase in these prices will cause its payments to the buyer to increase (or its receipts from the buyer to decrease). Thus, to the extent that the majority of its supply portfolio is committed under contracts for differences, the generator's incentive to exercise market power in the real-time market will be reduced or even eliminated.

Installed Capacity Obligations. An additional option to help prevent physical withholding in real time markets is to require load serving entities to own or contract for generating capacity sufficient to meet their load's peak requirements plus a reserve margin. Ideally, such contracts would be for a year or more and would take into account the forced outage rate of each generating unit that the load serving entity expects to use to satisfy its load. Each load or load serving entity would be required to make available to the ISO each operating day sufficient capacity resources to meet the energy demands of its non-curtailable load. Loads that can be curtailed at specific price levels could be exempted from the installed capacity requirement. Under this approach, loads or load serving entities that fail to meet their installed capacity obligations, or whose capacity resources are not sufficiently reliable, could be subject to penalties tied to the cost of purchasing additional supply in real time.

Coordinating and Controlling Outages. In order to limit the ability of generation owners to use the declaration of a forced outage as a means to withhold capacity from real-time markets, an ISO could require all generation owners that are connected to the

ISO's system to schedule their maintenance and other planned outages on an annual basis. The ISO would require owners to adhere to the approved schedule unless alternative arrangements can be made without jeopardizing system reliability or market performance. Also, the incentive for generators to withhold capacity from real-time markets can be minimized by assigning the risk of unplanned outages to the generation owner. This can be done by assessing penalties for unplanned outages tied to the cost of purchasing replacement energy in the real-time market.

Market Rules to Prevent Economic Withholding

There are many measures that can theoretically prevent economic withholding in real-time markets. However, given the significant role of bi-lateral markets in most regions, including California, any consideration of market rules to prevent economic withholding in real-time markets must also take into account the impact of those rules on bi-lateral markets as well.

Bid caps. One way to prevent economic withholding in real-time markets is to place a cap on the bids of individual generators. Because they can be resource specific, bid caps are particularly useful for controlling local market power that arises when there are transmission constraints. The rationale for employing bid caps derives from the fact that, in competitive markets, individual suppliers have an incentive to bid their marginal costs. Thus, under this theory, capping bids at marginal cost is reasonable because it only requires generators to bid what they would bid in a competitive market, while allowing them to receive the market clearing price for all of their output. However, as noted above, marginal production cost is not always an accurate measure of what a competitive generator would bid in real-time markets. Because generators have start-up and no-load costs and may be energy limited, their bids may sometimes exceed marginal production costs even when they operate in a competitive environment.

Price caps. Placing a cap on the overall market price is a commonly used tool for limiting economic withholding. In choosing the level for the price cap, the object is to set it low enough to prevent economic withholding, yet high enough to allow the market to clear and provide adequate compensation for generators. To encourage the entry of new generators, it is important that generators receive sufficient compensation both to cover the costs of production and to provide a contribution to capacity costs. Unfortunately, it is difficult to design a fixed price cap that satisfies all of these criteria all of the time. This is because a price cap that is high enough to clear the market in peak periods may allow the exercise of market power in off-peak periods, and a cap that is low enough to control market power in off-peak periods may not allow the market to clear on peak and, as a result, have adverse consequences for investment.

Payment scheme. In centrally coordinated markets such as those administered by the ISO, a choice must be made between setting rates for generation services at the market clearing price or at the as-bid price.[4] Proponents of the market clearing price approach note that it gives suppliers the incentive to bid their marginal costs. This is because, with a higher bid, they run the risk of having their bid rejected for being above the market clearing price, and with a lower bid they risk being called to operate when the market clearing price is below their marginal cost. When suppliers have an incentive to bid their marginal costs, attempts to exercise market power are easier to detect. Also, the use of the market clearing price approach provides a level of price transparency that facilitates congestion pricing and the settlement of forward contracts.

On the other hand, proponents of as-bid pricing claim that it benefits consumers by allowing them to pay only what individual generators bid rather than a market clearing price set at the level of the highest accepted bid. They also claim that as-bid pricing makes market gaming strategies riskier for generators. The theory is that, with market clearing prices, a supplier needs to bid only a small amount of its capacity at a high price in order to influence the market clearing price, whereas with as-bid pricing, a supplier would be putting a large portion of its portfolio at risk if it attempted to exercise market power by setting bids for all units at a high level.

However, these arguments generally ignore the fact that the incentives and optimal bidding strategies under the two approaches are entirely different. Clearly, if suppliers know that they are going to receive only what they bid, they will attempt to bid the market clearing price, a practice that introduces additional risks into the market. If the suppliers are successful, consumers will not see a benefit from the as-bid approach. Also, to the extent generators have market power, they will likely be able to devise strategies for economic withholding under as-bid pricing that are just as successful as similar strategies are under market clearing pricing. Furthermore, as-bid pricing greatly complicates the settlement of forward contracts in real-time, as well as the pricing for congestion management and ancillary services. Moreover, limiting the market clearing price auction in the real-time market (expected to be no more than 5% of load under the terms of the December 15 order) significantly limits any price increasing effects that may result compared to an as-bid scheme for such markets. It will also be significantly easier for the Commission to administer.

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[4] On this, see, e.g., *Pricing in the California Power Exchange Electricity Market: Should California Switch from Uniform Pricing to Pay-as-Bid Pricing?* (Blue Ribbon Panel Report), by Alfred E. Kahn, Peter C. Cramton, Robert H. Porter and Richard D. Tabors, California Power Exchange, January 23, 2001.

Cost-based regulation. Historically, rates for power in wholesale markets were regulated on a cost of service basis. Despite the problems that have occurred recently in California markets, there is still ample evidence to suggest that the generation of electricity can be efficiently provided by competitive markets. Although the exercise of market power can be controlled by cost of service regulation, such an approach entails numerous inefficiencies that have been well documented elsewhere. While a return to cost-based rates might provide short-term relief from excessively high prices, it would be complex to administer (requiring, for example, rules for cost allocations and curtailment schemes in the event of capacity shortfalls), and it would have a detrimental effect on the long-run health of the industry. After all, it was the high power cost to consumers under cost-based regulation that led to the realization of the importance of competitive markets for electric power. Reimposing cost-based regulation would require a complex and contentious process of establishing a cost basis for generation that has already been divested, a process that is almost certain to increase costs to consumers compared to historical levels given the cost at which the generation capacity was acquired. Since traditional cost of service regulation has proven undesirable in the long run, reimposing it now would be complex, burdensome and uncertain, raising overall costs to consumers. Under these circumstances, returning to cost-based regulation will not provide meaningful consumer benefits and runs a serious risk of discouraging investment in needed generation and transmission infrastructure.

5. Recommended Monitoring and Mitigation Approach

This section describes the monitoring and mitigation measures for the California market recommended by staff. Present market conditions and the current breakpoint approach are described first, followed by the monitoring and mitigation provisions recommended given current conditions. These provisions are selected from the measures discussed in the previous section. Alternative measures not included in the recommendation are discussed in Section 6.

Background

One of the key benefits of competitive markets is their ability to signal scarcity of resources through high prices in the market, prices which provide a basis for future investment in supply capacity or demand response capability. If demand can adjust quickly and new supplies can enter the market, then market power is unlikely to be a problem. Developing recommendations responsive to these conditions encounters a fundamental problem: distinguishing between the effects of scarcity of supply and the effects of the exercise of market power. Both effects are characterized by higher than normal prices, and both are more likely to occur when supply and demand get out of balance. The potential for scarcity means that short-term prices in competitive markets can rise above short-term production costs. The potential for market power in electricity markets means that short-term prices from market power exercise can easily seem to be the result of scarcity. Because of the limited demand response in today's California markets, small quantities of supply withheld from the market can lead to very high prices and create strong incentives to withhold supply unless the price received is well above a competitive market response.

What initially appeared to be short-term price spikes in California in June 2000 have mutated into long-term market conditions. The present power market in the West is one of continuing supply scarcity and inflexible demand. The result is a market very different from other problematic markets (such as the Midwest in June of 1998) where the imbalance of supply and demand has been relatively short-lived and more competitive supply conditions returned to discipline prices. Under these conditions, market forces are unable to exercise effective discipline over prices in those hours when reserve deficiencies occur. Even if California succeeds in expediting new supply and demand reduction measures, it will take some time before reserve deficiencies can be brought to normal levels. For this reason, staff recommends price mitigation in those hours when reserve deficiencies occur, (for example during Stage 3 emergencies) to allow the transition from the current market conditions to more normal market conditions in the least disruptive way for both energy providers and consumers.

Ideally, monitoring and mitigation should let prices rise to competitive levels that reflect scarcity but not to levels that reflect the exercise of market power. There is no simple formula for doing this. A market that clears at the short-term production cost of the highest cost generating unit dispatched provides payments for scarcity to all units with lower costs.[5] However, there is no *a priori* guarantee that these payments will provide sufficient compensation for supply, and markets may sometimes clear at levels above this short-term production cost. In markets where demand is able to set a limit on the price it will pay, however, the price at such times will be bounded by the willingness of buyers to pay the prices sought by suppliers. When demand cannot set such a limit, the resulting price is set solely through competition among suppliers. If supply/demand conditions are sufficiently tight and publicly known, and demand cannot respond, suppliers may have very little incentive to offer supply at what would be otherwise called competitive levels.

Under these conditions, there may be no need for any type of cooperation or coordination among suppliers to set a high price, because all suppliers are aware of how tight supplies are relative to the amount they have to offer and even rudimentary knowledge of the general structure of the market will substantially diminish the willingness of a supplier to offer supply at a low price. If the prices that result are not sustained over long periods at high levels, then there may be no significant market power concerns and the market may be providing adequate price signals to provide incentives for new supplies or for the development of demand response that together serve as the best long-term response. However, if high prices above a level that should induce new entry are sustained for longer periods and new supplies are not able to enter in time to discipline the short term price levels, some form of market price mitigation may be needed to address the impact of prices that reflect market power, i.e., prices over competitive levels that are sustained for a significant period of time.

Staff's recommended price mitigation is a response to current market conditions. However, staff strongly recommends that the price mitigation be in place only for a defined and limited period. Successful mitigation should permit prices to fulfill their role in the marketplace, providing incentives for the development of new and more efficient infrastructure in electricity supply, transmission and demand reduction. The marketplace needs confidence that a credible timetable is in place for the removal of this regulatory constraints to competitive markets. Simply put, the price mitigation must be limited

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[5] When all generators with marginal opportunity costs less than this price are generating, these payments are called “scarcity rents”. Suppliers who can produce at a cost below the market clearing price earn payments that reflect the limited availability of units that can produce at their production cost.

enough in scope and term that it will not serve as a crutch to delay needed long-term improvements.

Current Breakpoint Approach

In the December 15 order, the Commission settled on the $150 breakpoint approach to the then current market after considering and rejecting a number of alternatives. The breakpoint method was seen as a temporary, interim solution with limitations as a longer-term alternative. Ultimately, it was recognized consumers derived very little benefit from it, because it did not allow demand to respond to high prices and did not allow any transparency to prices.

One limitation to the breakpoint method was the *ex post* nature of the mitigation. Any correction is made after the fact, potentially altering business arrangements that appeared reasonable to the party when made, but were later judged by regulators to be unacceptable. Such conditions may at times be necessary, but they are undesirable if alternative mitigation strategies are available that do not require changes to prior business outcomes through subsequent regulatory action.

The difficult and potentially labor intensive review of transactions is a second limitation of the breakpoint approach. Review of individual transactions is burdensome for staff and the reporting parties. . The Commission directed the staff to develop new mitigation procedures to replace the after the fact review, so that adverse market outcomes could be identified and avoided, rather than reviewed after the fact for potential refund.

Another difficulty with the present breakpoint approach is the lack of market transparency when there are transactions above the breakpoint. When the market is allowed to clear, the price paid by buyers and sellers is posted and seen by all market participants. However, if a significant portion of the bids are above $150 and sellers are paid their bids, subject to refund, it is not clear what actual prices will ultimately be paid. Since prices above the breakpoint are not posted and are subject to revision, organized markets subject to the breakpoint rule do not provide price signals above the level of the breakpoint.

For these reasons, the staff recommends that the breakpoint approach be terminated for transactions ending April 30, 2001.

Recommended Monitoring and Mitigation Approach

Underlying Design Principles

The comments, suggestions and proposals received make it abundantly clear that there is no single right answer. In making the difficult choices needed to design price mitigation for the present circumstances in California, staff adhered to these core principles:

- Buyers and sellers need to know the rules up front and have confidence that those rules will not be subject to constant change or interpretation.
- Prices should be mitigated before they are charged, not after.
- The recommended price mitigation should be as surgical (least intrusive) as possible and last for as little time as possible. This should be no longer than needed to allow long term solutions to be attainable.
- The price mitigation should be as market oriented as possible and adopt market solutions and mechanisms to the maximum extent.
- The pricing provisions must encourage, and not discourage, the critically needed investment in infrastructure (e.g., increasing generation supply, adding required transmission, implementing demand response.)

Staff Proposal

Staff recommends that the ISO conduct a real-time auction with associated measures to mitigate the impact of physical and economic withholding. The auction should have the following characteristics:

- *Coordinating and Controlling Outages*. All planned outages by units which have signed a Participating Generator Agreement (PGA) with the ISO should be coordinated with, and approved by, the ISO. Unplanned outages should be closely monitored by the ISO and questionable outages should be reported immediately to the Commission for further investigation by the Commission.
- *Selling Obligations*. Sellers with PGAs should be required to offer all their capacity to the ISO in real time if it is available and not scheduled to run. Load Serving Entities should be required to state the price at which they will curtail their loads, and to identify which loads will be curtailed.

- *Price Mitigation*. When called upon to provide available (unscheduled) capacity in real time, PGA units would be price mitigated only in those hours when there is a reserve deficiency (e.g., Stage 3.) During these hours all PGA units obligated to sell capacity in real time would be paid the marginal cost of the highest-priced PGA unit called upon to run.

- *Real-time Price Mitigation for Each Generating Unit.* Each generating unit should be required to have a standing, confidential price based on its marginal costs, to be used by the ISO to establish the real-time market clearing price when mitigation is appropriate.

- *A market clearing price.* All energy offers that are accepted in the real-time market should be paid the applicable market clearing price.

- *Conditions for Invoking Mitigation.* Application of mitigation should be restricted to critical operating periods, such as emergencies when reserves are scarce and load must be reduced.

Since the PX has suspended the day-ahead market effective January 31, 2001, the markets that are addressed in the proposal are the ISO ancillary service and supplemental energy markets. The focus of the measures described is on the energy bids into these markets for resources that are dispatched by the ISO in real time.

Each of the recommended provisions is discussed further below.

Coordinating and Controlling Outages. The California ISO currently has procedures for coordinating planned outages, but has limited authority to approve planned outage schedules, because the ISO's approval authority applies primarily to RMR units. The current ISO authority may need to be strengthened to achieve greater systematic control over all units (including those of the IOUs) that the ISO must dispatch, i.e., those units that have signed PGAs. The procedures for coordination and outage control should be coupled with reporting requirements to the Commission and expedited review when disputes arise. Unplanned outages would continue to be closely monitored by the ISO and questionable outages should be immediately reported to the Commission.

Selling Obligations. The requirement to offer generation capacity would only be imposed on the ISO's real-time market. It would not be imposed on bilateral markets or on the ISO day-ahead markets, and suppliers would be free to make other sales arrangements prior to real-time and schedule these arrangements in accordance with the normal ISO scheduling requirements. But all available unsold capacity would be required to be available to the ISO for dispatch in real-time.[6] To implement this, PGA generators would be required to propose to the Commission, in advance, a dependable capacity for each unit as well as certain operating parameters necessary to calculate marginal costs, such as heat rate. The Commission staff could then use a published fuel cost such as that which is available in *Gas Daily* and emission credit data (where applicable) to determine the correct price that can be used for mitigation purposes. This would then be the basis upon which the ISO would use pre-determined standing prices to mitigate prices during times of reserve deficiency (e.g., Stage 3).

Load Serving Entities should also be obligated to identify the loads that would be curtailed, and bid the capacity of these loads into the market, along with the price at which the load would be willing to be curtailed. The ISO should work to provide a mechanism for these demand bids to be implemented as part of the ancillary services market.

Price Mitigation Procedures and Conditions. Staff believes that price mitigation should be invoked only in those hours when the ISO experiences reserve deficiency. These hours are those which are extremely conducive to the exercise of market power by suppliers. One alternative would be to invoke mitigation only during severe (Stage 3) conditions, as long as the basis for the emergency conditions could be objectively determined independently from the price in the market so that emergencies were not called in order to depress market prices.

Market Clearing Price Auction. The recommended approach to mitigation would employ a market clearing price design that would be used during normal market conditions. During periods when mitigation is imposed (in times of reserve deficiency) this "auction" would be modified for the ISO to choose between standing supply prices and demand bids necessary to clear the market efficiently. In this regard, the ISO would choose between demand bids and price mitigation levels on file that are intended to be set at the generator's marginal costs. All generators would be paid at the marginal cost of the highest unit.

In those hours when the ISO experiences a reserve deficiency and price mitigation is invoked in the ISO real time markets on PGA units, staff believes that a single market clearing price design is appropriate. This is different than the as bid, plus justification approach followed in the December 15 order. Staff nevertheless believes that the single market clearing price approach should be adopted because the mitigated price will closely

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[6]To avoid the potential for exercise of market power in the quantity of capacity proposed, the level of capacity should be based on standard engineering principles.

resemble the price that would transpire under competitive (i.e., non-reserve deficiency) conditions. In a normal competitive market, suppliers receive a market price for their product and obtain a return above their costs because there is only a limited (i.e., a scarce) supply of the product available at the cost they are able to offer to the market. When suppliers are paid their bid, rather than a market clearing price, compensation beyond variable cost must be built into the mitigation payment for the individual bid. Very simply put, this induces bidding inefficiencies.

Staff believes these real-time provisions respond to present need for mitigation in the California market, and further believes that the implementation of these provisions will contribute to longer-range solutions. These solutions will be needed to address key aspects of market development that cannot be treated solely through real-time mitigation. In particular, wider regional solutions are needed to address the role of imports and exports between California and the rest of the West. Also, the real-time ISO market is only one part of a larger dynamic market that includes bi-lateral trades and active forward markets. Absent the development of a western RTO, problems raised by imports will remain largely insoluble, and the development of viable forward markets will subject to continuing uncertainty. While these problems are not addressed in the proposal, all monitoring and mitigation considered for the California market must avoid inhibiting these key longer-term developments.

Potential Difficulties in Implementing Staff Proposal

As the December 15 order pointed out, there are no easy answers to the current problems in the California market. Staff has identified the following difficulties that could confront implementation of its recommended approach.

Bidding Obligations on Imported Power. Imported power is a large part of the California supply and mitigation in one area tends to discourage imports from adjoining areas. Bidding obligations for imported power present difficult choices. One approach might be to require any supplier who wished to sell in the ISO market (or use the ISO's transmission grid to make sales) to agree to make uncommitted capacity available to the ISO in real time if it is not committed to any other market as a condition for sales to the ISO. However, this condition could be challenged legally and it would represent a significant condition on supply outside California that commits Western resources to the California market in real time, and, as a practical matter, is feasible only for organized markets such as the ISO market in California.

Incentive Effects on Load Scheduling. One potential difficulty arises in conjunction with penalties imposed on loads if they fail to schedule 95% of their load prior to the real time market. The December 15 order fixed those penalties at two times the cost of energy not to exceed $100/MWH. Consequently, load will be able to purchase in real time at no more than $100 over the real time price. If the real time price is mitigated and bilateral prices prior to real time are likely to exceed the real time price by more than $100, then load has an incentive to pay the penalty in real time and underschedule their load prior to real time. This may not occur frequently, since a marginal cost based clearing price can be quite high, given fuel and emission costs, but it is difficult to determine a mitigated price that will give much confidence in such a benign result. Raising the penalty may not be the answer either, since a penalty that is too high may provide supply with the incentive to raise the price to load prior to real time. A better incentive to load to avoid purchase in real time would be to avoid artificial constraints on the real time price so that it is high enough to provide disincentives for purchasing supply at the last minute.

Treatment of Purchased Power. Another difficulty concerns the treatment of purchased power and applying the bidding provisions to mitigating portfolios of purchased power maintained by power marketers. Price mitigation on certain units (PGA units) cannot easily be extended to power marketer portfolios. Seller specific price mitigation based on purchased power costs may provide incentives for generators to sell to power marketers at above cost rates, permitting marketers to evade the mitigation that would otherwise have been placed on the power. In fact, there are allegations that this occurred when the ISO had hard caps in place. This difficulty can be averted by basing the price mitigation for marketers on the specific cost of the generating unit providing the power. However, where there are pre-existing power purchase agreements, mitigation based on marginal cost may disrupt the terms of agreements made under earlier, and quite different, market conditions. The agreements may have been made on a competitive basis, even if the payment mechanism provides for energy payments above the variable cost of the unit in real time. For example, a longer term agreement may recover a significant portion of fixed costs in an energy payment, or may contain payments for availability of capacity to the purchaser of power. A requirement to sell at marginal costs may impose real losses to the generator, by limiting the ability of the generator to recover costs under the existing agreement.

Mitigating Prices During Emergencies. Conditioning mitigation on emergency status raises the problem of constraining the price in a market when prices should be freed to provide maximum incentives for supply to enter the market. Several factors mitigate the force of this difficulty, however. First, under these conditions, the normal rationing effect of prices on demand has already lost much of its force. If load serving entities are required to state a price at which they were willing to curtail load, and the ISO were required to expedite incorporating such bids into its dispatch, some of this rationing effect may be restored. Second, only 5% of the load or supply is covered by price mitigation for the purpose of ensuring no physical withholding, and the mitigation is designed to ensure the uncommitted supply covers all real time costs. Third, sellers would be free to arrange deals outside the real time market without any pricing restrictions.

Setting a Price Component for Scarcity. Mitigation seeks to curb market power as a protection for customers who are unable to respond to its exercise, but it is incomplete if it fails to provide proper price signals to both supply and demand (load). When resources are scarce, the mitigation procedures need to permit the price to rise above the highest marginal operating cost of generation. In theory, bidders should be permitted to add a component to their bid for scarcity under these conditions. In practice, however, there is no simple way to set this value. An overall cap at a very high value, such as the $1000/MWH cap used in the eastern ISOs, could be used to limit the potential damage. While this approach has not proven very successful in the past in California, any adverse affect could be greatly lowered if it is limited to no more than 5% of the market. However, such hard caps are a blunt instrument and can have adverse effects even if confined to a small part of the market.

A Possible Variation on the Proposal

Staff believes the recommendation described above is a reasonable approach, given its desirable theoretical properties and the depth of the market problems confronting California during the present generation shortages. However, staff also recognizes that the proposal represents a high degree of market management of the real-time market through regulation, a level of market management that may pose problems in practice. A more limited variation on the staff proposal would consist of the following elements:

- Retain proposed provisions on bidding obligations, coordinating and controlling outages, market clearing price design and conditions for invoking any applicable price mitigation.

- Set a very high payment level (as opposed to the price paid to the highest PGA unit dispatched in real time), or have no level of payment at all.

- Require suppliers to assume all risk of unplanned outages. If supply is free to set the price it is willing to accept, then it should be required to assume the associated risk of outages.

- Implement these provisions only if a sufficient percentage of the load is covered by long-term contracts. As described in the previous section, staff believes long-term contracts can be a highly effective mechanism for controlling the exercise of market power in real-time. If a sufficient amount of load is protected under long-term contract, then the cost of implementing a system of real-time price mitigation may be outweighed by the benefits of letting the remaining load and supply trade freely to establish the price in real time. However, as discussed in Section 2, this report does not take a position on the contract price or the exact level of contracting appropriate for this market.

The provisions of this alternative proposal are similar in form to the proposal of the CalISO Market Surveillance Committee, by emphasizing long-term contract conditions and a real-time bidding requirement, but freeing the real-time market from detailed price controls. However, this variation does not follow the specifics of the MSC proposal. Rather, it includes an option to set a high payment level rather than none at all, in order to mitigate potentially unbounded exercises of market power in real-time. Also, where the MSC proposal lays out specific regulatory requirements for the long-term contract market, the staff proposal recognizes the need for a sufficient level of long-term commitments to ensure reasonable market outcomes, but does not take a position on exact nature of these commitments.

Monitoring Procedures and Information

The ISO may be motivated to declare a reserve deficiency to depress the price (rather than keep the lights on) because of its current Board. Consequently, the Commission should monitor the application of the mitigation measures in order to ensure they are applied objectively. Monitoring procedures and information should provide for:

- Weekly reporting of schedule, outage and bid data from the ISO to keep the Commission informed on the current market performance. Knowledge of these conditions on an ongoing and up-to-date basis is essential, if the Commission is to provide an independent and informed assessment of status of key elements of the mitigation plan, such as the level of unplanned outages and conditions that could cause price mitigation to be invoked.

- Weekly ISO/Commission staff conference calls to provide staff and the Commission with advance warning of potential market problems, accurate understanding of relevant details in the reported information.

This information will provide the Commission with an understanding of the performance of the California market. To ensure independent application of mitigation, the Commission should receive information on these operating conditions in order to be able to conduct informed, independent assessment of any application of price mitigation rapidly if questions arise.

Phasing Out Mitigation

In the long run, the current problems in the California market can be effectively addressed only through the development of badly needed market infrastructure. The events in California since last May have underscored the current need for new infrastructure in all segments of the electric power industry, but the failure to add infrastructure has been a longstanding one. [7]

The need to expand the capacity of the current transmission grid in California has become particularly clear over the last few months, as power prices in Northern California have consistently exceeded those in Southern California, and shortages of power in Northern California have been the persistent cause of emergencies. A substantial part of both the high prices in the north and the power shortages can be traced to the limited capacity of the California grid, in particular to the limitations on Path 15, the major transmission path in the middle of the state.

Finally, development of the demand side of the power market is critical, and cannot take place without investment in an infrastructure that enables customers to see and respond to price signals. Part of the needed development will be in information and control technology that enables load to respond, but institutional development in the form of rules and protocols for demand participation in the market are needed as well.

This mitigation proposal is intended to address current conditions, for the purpose of facilitating the development of a stable, self-sustaining power market in California. The proposed mitigation must be viewed as a temporary measure, so that mitigation is not relied upon as a substitute for market improvements that should otherwise be implemented. Market participants should have the certainty that the provisions of the proposal will be phased out over time, on a schedule known in advance, so that development of needed infrastructure can proceed without undue risk.

The maximum period the Commission should consider for the price mitigation is one year. This period should be sufficient for the basic supply and demand conditions to improve to a point where the level of direct mitigation in the market envisioned here can be removed. Moreover, a periodic reduction in the level of mitigation could be established at the time mitigation is put into effect. Both demand and supply infrastructure development over the selected period will be key to improving the market

[7] See *Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities*, November 1, 2000, page 5-3.

conditions that have made this mitigation necessary. Current plans in California call for large reduction in demand for next summer. On the supply side, the California Energy Commission currently anticipates 5,000 megawatts of generation additions for summer 2001. On the demand side, within 6 months the ISO should have changes in ancillary services bidding protocols that allow load to participate. And within the year, LSEs should be able to provide balanced schedules that include curtailable load. If these targets are not met, and over reliance on mitigation measures as a substitute for real market developments appears to be a reason, the Commission should consider further measures such as capacity obligations on Load Serving Entities (see next section), or phasing out the proposed mitigation measures rapidly.

6. Other Alternatives

This section discusses proposed market monitoring and mitigation alternatives that have been suggested, either in the comments or elsewhere, but were not incorporated in the staff recommendations. Each alternative is described briefly, along with a discussion of its potential benefits and potential difficulties.

Mandatory Forward Contracting by Suppliers

The CalISO, the CalISO Market Surveillance Committee, and the California Public Utilities Commission assert that all California generators and entities selling into the California wholesale market should enter into long term contracts for a term of not less than two years and in amount equal to at least 70 percent of their capacity. Failure to do so would result in the application of more restrictive bidding conditions than those that would apply to the 70 percent minimum. Staff does not recommend mandating a specific level of forward contracting at this time for several reasons. The State of California is now in extensive contract negotiations with parties owning generating capacity in the state. Intervention at this time could disrupt those negotiations and affect the price and terms of arms length transactions that may establish a market benchmark for the reasonableness of long term contracts. It is also not clear how such a proposal might be applicable, if at all, between generating capacity located within and outside the state. Given the problems with applying the forward contracting proposal to two different types of capacity, this recommendation would require further analysis and comments by the parties. Finally, these issues may become less important depending on the success of the State of California in negotiation contracts with the capacity owners.

Obligatory Capacity Acquisitions by Load Serving Entities

The CalISO also recommends that all Load Serving Entities (LSEs) be required to enter into capacity contracts that cover some minimum percentage of their needs, with an ultimate threshold of 115 percent of peak need. Failure to do so could result in penalties for a non-complying LSE. It is unclear what threshold the LSEs could reasonably be expected to obtain given the current supply situation in the entire WSCC area, and as a result it may be difficult to implement this proposal by May 1, 2000. Imposition of the requirement at this time may also be inconsistent with the State of California's efforts to contract for capacity that can be available under constrained market conditions in the WSCC region. Staff therefore recommends that this suggestion be one of the long-term options considered in a further technical conference but does not recommend it as part of the replacement for the $150 breakpoint.

Regional Solutions

Several commenters continue to suggest that a regional solution should be adopted to what is clearly at this time a regional problem. However, suggested regional solutions to date have all involved some type of a regional price cap for wholesale electric prices in the WSCC region. That suggestion suffers from the infirmity that outside of California the wholesale market is primarily a bilateral market with no central exchange, which significantly increases the administrative difficulty of administering a price cap, and existing long term contracts would likely fall outside the scope of any such cap regardless of the current per megawatt cost of the power delivered under such contracts. Moreover, much of the power production in the west outside of the California is owned by entities that are not subject to the Commission's jurisdiction. This makes the imposition of regional price caps even more complex than any imposed within a single state. In any event, adoption of such a complex regional solution is not appropriate in the context of the narrow proceeding adopted by the December 15 order.

Appendix: Summary of Comments on Market Monitoring and Mitigation for the California Wholesale Electricity Market

This appendix provides a summary of the comments filed in Docket EL00-95-012 on market monitoring and mitigation for the California wholesale electricity markets. Comments are summarized first, followed by reply comments.

Summary of Comments

California Independent System Operator Corporation

The CalISO presents a detailed proposal for market power monitoring and mitigation that includes a four-step process for market power mitigation. The first step is to require a significant level of forward contracting by suppliers in California. Specifically, the CalISO proposes to require suppliers to have 70 percent of their portfolio covered under forward contracts at just and reasonable rates. In the second step, the CalISO proposes to establish an Available Capacity Reserve (ACR) requirement where load serving entities must make available to the CalISO a specified amount of capacity, perhaps equal to 115 percent of their seasonal peak load. To encourage suppliers to make capacity available so that load serving entities can meet this ACR requirement, the CalISO proposes to require suppliers to bid all of their available capacity into one of the energy or ancillary service markets, subject to penalties for non-compliance. The third step involves the mitigation of locational market power. The CalISO states that it will propose a permanent solution to this problem as part of its congestion management reform proposal. In the interim, it proposes to mitigate the bids of entities possessing local market power by limiting the bids to variable cost or some appropriate measure of market price. In the fourth step, which the CalISO states is designed to prevent economic withholding, the CalISO proposes to establish bid price thresholds, such as variable cost or opportunity costs for energy limited resources plus a fixed margin. The CalISO states that such thresholds would be set so as to send strong price signals to both demand and supply to encourage development of price responsive demand and new investment in generation. Finally, the CalISO states that it intends to develop and file with the Commission a comprehensive market power mitigation proposal, as well as a planned outage coordination requirement and revised policies regarding the provision of market information to regulatory agencies.

The CalISO also includes in its comments its response to presentations made at the January 23 technical conference.

**California Independent System Operator Corporation,
Market Surveillance Committee**

The MSC offers a proposed market monitoring and mitigation plan for the California electricity market. The MSC states that three features of the plan are crucial and must be implemented together or not at all. The first is a requirement that all sellers of energy and ancillary services in California, besides the three California IOUs, offer forward contracts for at least 70 percent of their expected sales into the California market over the next two years at the average competitive benchmark price for this time period computed as described in the December 1, 2000, MSC Report. Entities that do not offer the required contract quantities at the competitive benchmark price will be subject to cost-based rates for all sales they make into California. The second feature of the MSC's proposal is to eliminate all price or bid caps, including the Commission's soft cap, on the markets for energy and ancillary services in California once these forward contracts are in place. The third feature is a capacity availability standard that would apply to all market participants located in California, including those subject to cost-based rates. This would require all generators to submit annual planned outage schedules that would be approved by the CalISO. At all times besides those previously scheduled with the CalISO, all generation units would be required to submit standing bids into the CalISO's real-time energy market for the difference between the unit's nameplate capacity and its final energy schedule at whatever price it chooses. If a unit's bid is selected and it or a suitable substitute unit is unable to respond to CalISO dispatch instructions, the unit's owner must purchase this quantity of energy in the real-time market. The MSC states that this availability standard effectively assigns the risk of forced outages to the unit owner rather than the CalISO. Lastly, the MSC states that the real-time trading charge recommended in the December 1, 2000 MSC Report should be implemented.

State of California Public Utilities Commission

The CPUC notes that some of the parties at the January 23, 2001, technical conference sought to limit the scope of the conference to market monitoring. However, the CPUC asserts that it is clear from the Commission's December 15, 2001, order that the appropriate scope of the technical conference, as well as the Staff's proposal to the Commission, should include both a market monitoring and market power mitigation plan. The CPUC states that the Commission, in its December 8, 2000, order, eliminated all price caps in the California PX and CalISO markets in order to attract generation supplies into the California markets. However, the CPUC asserts that volumes in the PX did not increase, and that instead buyers paid up to six times as much for the same quantities of power. The CPUC claims that the December 15 order has failed and the Commission now must fix a just and reasonable rate as required by section 206 of the FPA. The CPUC claims that the most effective means for the Commission to mitigate market power and restore a functioning market in California is to require mandatory forward contracts for a substantial portion of the portfolios of in-state generators and marketers that have purchased from in-state generators at a just and reasonable rate. The CPUC suggests that the term of such contracts should be on the order of 18 to 36 months and the pricing should be based on published forward gas prices in the producing basins, plus transportation costs. The CPUC recommends that, whatever other remedial measures are adopted as a result of this proceeding, the Commission should maintain the requirements that market participants and the CalISO report bids and transactions exceeding $150 to the Commission on a permanent basis. The CPUC also recommends eliminating the provision of the December 15, 2000, order that allows refund liability to expire 60 days after reports are filed unless the Commission takes affirmative action. Furthermore, the CPUC believes that the Commission must articulate a process by which the state and other affected parties can forward claims for refunds or other relief based on the bid and transaction reports. Finally, the CPUC notes that the December 8, 2000, order waived certain regulations applicable to Qualifying Facilities through January 1, 2001, and that the December 15, 2000, order extended the waiver through April 30, 2001. The CPUC requests that the waivers be extended beyond April 30, 2001.

California Electricity Oversight Board

The Oversight Board offers the following recommendations for market power mitigation (a) there must be a comprehensive and shared vision of how the wholesale market should be structured rather than continual incremental changes, (b) there should be clear and simple market rules and transparent pricing, (c) Scheduling Coordinators should be investigated and monitored to address the potential abuse of market power, (d) whether or not the CalISO performs market monitoring, state and federal agencies must be able to perform this function independently, (e) market monitoring must include the natural gas market, (f) the future wholesale market should include availability standards for generation and load. It is imperative that California develop a wholesale market structure that lends itself to easy monitoring and mitigation.

California Department of Water Resources

DWR believes that flexibility in forward contracting decisions on the part of the parties, including decisions regarding all terms and contract periods, to those contracts is an essential element of developing a stronger more developed market. DWR has been unable to confirm that the proposals before FERC will not impede compliance with the requirements and objectives set forth in AB1X. On this note, DWR requests that the Commission restrict the scope of this matter and take action in this regard to ensure DWR's ongoing endeavors to obtain needed power supplies through forward markets will not be impeded, and develop a Market Monitoring and Mitigation program that recognizes the recent California legislative events. This program should include a careful determination of the amount of reserves needed, as well as an adequate phase in period that takes into account current shortfalls of generation within the State.

County of San Diego, California

The County of San Diego states that the Commission must take decisive action to assure that prices going forward do not exceed just and reasonable levels, and must order refunds of prices in excess of just and reasonable levels that have been charged since May 2000. The County of San Diego generally supports the CalISO's market power monitoring and mitigation proposal and urges the Staff to include in its own proposal the essential elements of the CalISO proposal. However, the County of San Diego states that it does not agree with the CalISO's proposal to allow a fixed margin above marginal production cost to be included in resource specific bid limits. In addition, the County of San Diego disagrees with the CalISO's suggestion that the Commission refund review period and a supplier's obligation for refunds should be limited to sixty days after a transaction. Finally, the County of San Diego believes that if monitoring and mitigation measures are to be effective, they must apply to the entire Western region.

Northern California Power Agency

NCPA states that congestion management is integral to any attempt to control market power, it should be a primary focus of this Commission, or of any monitoring program. The failure to deal with significant constraints can dramatically impact market definition, and results in an analysis based on the assumption that customers can receive service from numerous suppliers, while in the real world, they cannot. Counterproductive and distorting market rules are also part of the problem. Currently the CalISO imposes a penalty on generators who fail to run when scheduled (due to forced outage or any other reason). Unfortunately, when shortages loomed in 2000, the CalISO ordered a total of 77 "no touch" days, when units were required to defer maintenance and remain on line. Units were also ordered to run far more often and longer than was contemplated in their design parameters. It is therefore no surprise that forced unplanned maintenance outages have reached unprecedented levels. The market monitor must be independent of the CalISO. Monitoring is at best a stop-gap measure. Ultimately, only construction of transmission and generation will ease load pockets and fully mitigate market power. CalISO relies on existing utilities to plan and construct new facilities, although those same utilities may benefit from existing congestion. FERC must insist that the CalISO be vested with this authority. This Commission must require the CalISO to disclose bid information on a next-day basis, and provide consumers and competitors with the information they need to detect market abuses. The market monitor should look for the exercise of market power, and for flawed market rules that either permit the exercise of market power to raise prices or have other adverse impacts on the operation of markets. NCPA does not advocate any specific test for determining when a bid is the result of exercising market power. However, the Commission should ensure that the definition permits bidders to recover opportunity costs, and especially replacement costs for input-limited resources.

The Modesto Irrigation District

Modesto emphasizes that a market structure should be developed which minimizes, if not eliminates, market manipulation by means of withholding of supplies. Unfortunately, the generation availability standards proposed to date do not adequately address the flexibility which irrigation districts such as Modesto must have in order to meet their obligations to balance their potentially competing lawful governmental function – irrigation and power production. In sum, Modesto urges Staff to take into account the distinct and unique needs of irrigation districts in developing a market monitoring and mitigation plan.

Mirant California, LLC, Mirant Delta, LLC, and Mirant Potrero, LLC

Mirant is concerned that the proposals submitted by the CalISO and by Edison stray far from the task at hand, and would effectively overrule many of the substantive findings and recommendations of the Commission's December 15 Order. The Commission should develop a market monitoring plan that focuses on 1) the identification of structural problems in the market and the development of effective solutions, and 2) the identification of defined anti-competitive behavior or violation of market rules. The market monitoring and mitigation plan sponsored by Mirant, Reliant, Duke Energy, and Williams largely tracks the PJM model. The basic parameters include a circuit breaker-like hard cap, with light-handed oversight of transactions underneath that cap. The generators proposal calls for the creation of a newly constituted, independent entity that will oversee market function on a regional basis. This market monitoring units (MMU's) primary responsibilities should be to identify structural problems in the market, to help craft necessary changes in market design or market rules, and to monitor for specific instances of abuse of market power or violation of market rules. The MMU should not have the authority to adjust bids or prices on an *ex ante* or *ex post* basis, but could recommend that the Commission impose penalties or sanctions. If thresholds or screens are used to determine whether undue market power has been exercised, the MMU should develop and publish those screens in advance, with input from all interested parties. For a perceived problem in bidding or violation of market rule, the MMU's first response should be informal notification to the appropriate market participant. If that does not resolve the problem, the MMU can issue a demand letter which can be shared with the Commission or Commission Staff. If neither of those approaches resolves the problem, the MMU should then be able to recommend further action. Specific penalties and sanctions should be imposed only by the Commission. In the PJM model, much of the real work on building consensual solutions to market design problems is done through the stakeholder committees - a structure that is lacking in California. The CalISO should consider if it would benefit from such a standing stakeholder committee.

Mirant believes that given the current supply problems in California and the potential burden on consumers from substantial and prolonged increases in wholesale electric prices, a temporary hard cap may be appropriate for the California market. Regardless of the precise damage control cap adopted (if any), the Commission should establish a definite expiration date for the cap, in order to encourage the development of demand side management programs and to maintain a strong commitment to increasing supply. If the Commission choose to continue using a soft cap as an interim way of screening for potential market power, it should consider whether it is appropriate to preserve the same breaking point. Longer-Term measures should be designed to allow for the subsequent development of a competitive retail market, and therefore may have to include special provisions if significant existing IOU loads choose an alternative supplier in the future.

Mirant California, LLC, Reliant Energy Power Generation, Inc., Duke Energy North America, LLC, Duke Energy Trading and Marketing, LLC, Dynegy Power Marketing, Inc., and Williams Energy Marketing & Trading Company

Joint Market Monitoring and Market Power Mitigation Proposal

MRDDW argue that the CalISO's proposal cannot serve as a useful starting point for developing a monitoring and mitigation plan. They claim that the CalISO's proposal calls for a comprehensive and immediate market redesign that would override the Commission's required market reforms, and that it rejects the possibility that parties will be able to successfully negotiate long-term contracts at prices that reflect a more rational market. MRDDW offers an alternative proposal that they state is designed to work within the parameters of the December 15 order and not to supplant it.

MRDDW claim that their proposal draws on the best features of the monitoring and mitigation plans of the northeast ISOs, particularly that of PJM. Regarding market monitoring, they state that an absolute prerequisite of their proposal is the complete independence of the ISO Board. Also, they assert that any entity charged with monitoring the California markets must be independent and must review market function and behavior on a regional basis. To this end, they argue that the Market Monitoring

Unit (MMU) should not be constituted as part of the CalISO until the ISO's governance structure has been modified to ensure its independence and includes out-of-state representation. MRDDW state that the MMU should not have authority to impose sanctions or penalties, or to adjust bids or prices. MRDDW believe that the MMU should develop objective rules and standards regarding acceptable behavior, and should be precluded from using a simple comparison of marginal costs to bids or prices as a means of screening for market power. MRDDW state that the MMU should monitor compliance with rules and standards, identify market design flaws, and monitor for the exercise of undue market power. They state that the MMU should engage in informal discussions with market participants regarding possible rules violations, issue demand letters when necessary, and make further recommendations, when necessary, to the ISO or RTO Board. They recommend that the MMU issue periodic reports and that it investigate market function or market participant behavior at the request of any participant. MRDDW state that the MMU should rely primarily on data routinely collected by the ISO or RTO and should not have authority to demand additional data. They state that the MMU should make available the data it uses to review and analyze market function, while ensuring that all confidential, proprietary and commercially sensitive data are protected.

Regarding market power mitigation, MRDDW state that if any form of price cap is retained past May 1, 2001, it should be in the form of either (1) a "soft" price cap that escalates over time and phases out in less that two years, or (2) a high "circuit breaker" cap. They argue that locational market power should be addressed as part of a comprehensive congestion management plan. They believe that suppliers should not be required to schedule or bid in to the California market except as agreed by contract, or through voluntary participation in an installed capacity market. They also believe that suppliers should be required to notify the ISO or RTO of planned and forced outages, and use best efforts to adjust planned maintenance schedules if possible. They state that the MMU should not be authorized to adjust bids or make ex post adjustment to market prices. Finally, MRDDW state that any market monitoring and mitigation steps undertaken now should not necessarily be viewed as permanent.

Electric Power Supply Association

EPSA believes that the MMU should be independent of the RTO and, ideally, should be a regional entity. The MMU should detect abuse of the rules, compile evidence of any abuses, and work with market participants to recommend any needed changes to market rules. The MMU's role should be limited to monitoring without enforcement authority, and in particular, the MMU should not have the authority to artificially adjust prices. It should instead recommend long-term structural solutions to problems that it finds. The MMU should identify the exercise of market power and assess anti-competitive behavior of market participants, including transmission owners and market buyers, as well as generation owners. EPSA argues that high prices alone are not proof of anti-competitive behavior or market power abuse. EPSA asserts that factors such as capacity value, opportunity costs, scarcity value and risk must be considered when assessing high prices. EPSA recommends use of a two-level market power screen. In the first level, the MMU would identify which prices exceed a competitive screen. In the second level, the MMU would attempt to identify specific anti-competitive actions that caused the higher prices. EPSA believes that the MMU should define safe harbor standards for documenting outages, failure to bid, and variations in bidding behavior. EPSA recommends that enforcement be left to the Commission or the Department of Justice.

Strategic Energy, LLC

Strategic Energy holds that California should not introduce Capacity Credit Markets (CCM), CCM's are ineffective at encouraging the development of new generation and provide no intrinsic value, CCM's are extremely flawed and extremely vulnerable to market power abuse resulting in bipolar pricing behavior that always approaches the penalty rate. CCM's should not be implemented in California and should be eliminated wherever they may exist. The Available Capacity Reserve (ACR) component of the CalISO's proposal should be rejected, any attempt to modify the ACR will fail, just as attempts have failed in other ISOs that have CCM's. The wholesale energy markets alone provide relevant revenue information that influences decisions to build new generators. The best long-run solution is to let developers respond to free-market signals reflected in forward energy prices. The best short-run solution to market power monitoring and mitigation is a political issue, and proscriptive intervention will undoubtedly lead to inefficiencies that will cost California extra.

Public Service Enterprise Group, Incorporated

PSEG believes that an RTO market monitoring unit (MMU) has an appropriate (although proscribed) role to play as an early warning system of market flaws as well as abuses of market power, once detected, the MMU should propose changes to correct flaws in market structure and rules. The MMU should not have the power to change prices retroactively nor should any pricing screens used by the MMU be made overly restrictive. In determining what degree of market power represents a harmful market power abuse, it is crucial that the MMU be unbiased and independent. Proper market design needs to focus on allowing markets to operate freely rather than shackling them with unnecessary and disruptive restraints. PSEG notes that the following market flaws are contributing to the market dysfunction in California. (1) The Power Exchange is separate from the ISO. PSEG has long held that such separation introduces opportunities for gaming and needless inefficiencies into the market by preventing the achievement of lowest market-clearing prices under all market conditions. (2) California did not maintain a capacity reserve requirement, instead it simply (mis)placed its reliance on the mantra "the market will provide." (3) Generation siting needs to be more efficient. (4) the market needs to be demand responsive. (5) Utilities and load-serving entities must be free to hedge their load obligations with longer-term, bilateral supply contracts that help mitigate exposure volatile spot markets.

PG&E Corporation

PG&E emphasizes that a comprehensive monitoring and mitigation program will not be effective in California or elsewhere unless it is sufficiently comprehensive, well-defined, completely clear in structure and process. Specifically, the program must provide monitoring, mitigation and enforcement; have clearly defined roles, responsibilities and relationships; rely on well defined standards, and institute enforcement action when necessary.

The Utility Reform Network and Utility Consumers Action Network

TURN/UCAN state that the Commission's soft cap with as-bid pricing above the cap have failed to provide just and reasonable rates and to protect ratepayers from the multi-billion dollar impacts caused by private generators. They propose instead the implementation of resource-specific, cost-based bid caps (RSBCs). They assert that the Commission should order the use of RSBCs for all generators until market power problems are no longer in evidence and bidding flexibility is appropriate. TURN/UCAN claim that RSBCs will immediately cure the problem of strategic biding behavior that amounts to economic withholding, which in turn drives prices to excessive levels. TURN/UCAN also claim three major advantages for the RSBC approach. First, they note that generators are required to bid their incremental cost, which, they argue, has always been the premise for competitive market bidding. Second, they believe that the current bidding software and uniform-price algorithms used by the ISO can still be used. TURN/UCAN claim that this results in lower transition costs and enables generators with lower incremental costs to obtain greater overall revenues. Third, they assert that the RSBC approach sends correct incentives for both current plant operations and future plant investment.

Grid Services, Inc.

Grid Services comments that the lack of product options in the CalISO Day Ahead Market may be limiting bids into this market. The CalISO presently purchases in the Day Ahead market a single product, a 10 minute energy product that can be called at any 10 minute interval over the operation hour. Any resource bid into this market is guaranteed its bid price for only the initially dispatched 10 minute interval. If the price dropped below the resource's bid price the CalISO cancels the dispatch order. The resource has the choice of reducing output or receiving the new 10 minute interval price. The energy procured through the OOM is typically purchased in blocks of at least an hour and sometimes strips of several hours in duration . A resource, knowing this second opportunity exists, may decide to limit bids in the CalISO Day Ahead market and wait for an OOM call. Grid Services recommends the addition of a Day Ahead hourly or multi-hour product to the existing 10-minute product. This should provide an incentive to the resource presently selling in the OOM and may attract new resources such as load that are not presently on the CalISOs OOM call list. Additionally, Grid Services recommends providing Load Serving Entities greater access to the Real Time market thus allowing them the opportunity to procure additional supplies as required. (2) Transmission is a necessary component to mitigating market power. In several load centers, transmission is required to create sufficient supply competition to avoid the opportunity for market power. The CalISO staff suggests the monitoring of generator scheduled and unscheduled outages and the placement of penalties or incentives to insure sufficient generation during peak periods. Grid Services suggests that any such monitoring and incentives/penalties should also apply to transmission. Additionally, Grid Services recommends that the Commission work with the State to remove impediments to the development of load side generation.

Summary of Reply Comments

California Independent System Operator Corporation

On February 14, 2001, the CalISO responded to several aspects of its proposed market power mitigation plan raised in the comments submitted by various participants. With regard to the Forward Contracting Requirement the CalISO responds to Mirant's objections by emphasizing the seventy-percent forward contracting threshold is not a mandatory requirement, but is simply a proposed pre-requisite for a supplier to be subject to less stringent mitigation in the spot markets. Suppliers can choose to comply with the seventy-percent threshold, or not, based on their assessment of the financial benefit of their existing contract commitments and the profit to be earned by the remaining capacity under the proposed spot market mitigation measures.

The CalISO's draft plan for Available Capacity Reserve and Availability Requirements is designed to ensure that LSEs have an incentive to contract with suppliers at a level sufficient to satisfy their own load and meet their share of system reserve requirements. To achieve this the CalISO proposes to establish an Availability Capacity Reserve Requirement (ACR), LSEs must demonstrate to the CalISO a specified amount of capacity secured by ACR contracts. CalISO responds to Strategic Energy's claim that the ACR proposal will be costly without providing any benefit, and that the proposal is no different from Installed Capacity (ICAP) by stating that the ACR proposal and Availability Requirements are necessary to promote investment in generation and to assist in mitigating market power by ensuring adequate supplies to meet system loads and reserve requirements. CalISO believes that the ACR proposal, coupled with the real-time price bid mitigation will greatly lower overall operating costs in the real-time market, because much of the capacity for meeting load will have been procured and paid up-front. In response to Modesto's concern that the Availability Proposal doesn't adequately provide the flexibility required to balance Modesto's legal obligations with respect to irrigation and power production, the CalISO believes these obligations can be taken into account in the planning of Availability Requirement with provisions for seasonal updates in conjunction with the CalISO's outage coordination.

In order to prevent the exercise of market power in real-time, the CalISO proposes that FERC establish resource specific bid caps(e.g. variable cost or opportunity cost for energy-limited resources, plus a fixed margin). San Diego disagrees with the CalISO's proposal to include a fixed margin above the marginal production cost. The CalISO responds that a minimum adder is necessary in order to allow resources to recover their costs. TURN/UCAN support the concept of resource specific bid caps, but argue that these caps should change in direct relationship to prevailing fuel and NOx emission prices. The CalISO agrees that fuel prices be included for market power mitigation under the interim approach. However, for the longer-term local market power mitigation approach, the CalISO believes that fixed option payments should be made up front to cover costs other than fuel adjusted variable costs (start-up, gas imbalance penalties, emission credit limit violation penalties). Including such costs in an up-front payment, rather than including them as a margin in the resources mitigated bid caps, is the appropriate long-term solution because of the high frequency of occurrence and predictability of local reliability requirements in constrained areas of the grid.

With regard to the release of market information, NCPA argues that bid and price data should be disclosed the day after the operating day. It maintains that the current requirement to keep unit bid data confidential for six-months was a mistake. The CalISO notes that the release of bid data after a six-month lag, which was proposed in Amendment No. 25 to the CalISO Tariff, is consistent with Commission requirements for other independent system operators.

With respect to market power and the independence of the market monitor, Mirant suggests that the CalISO's plan is based on the unsupported assumption that market power is rampant and that the CalISO proposes broad and intrusive remedies without demonstrating that market power exists. The CalISO states that it has performed numerous studies and analyses which demonstrate the ability for market participants to exercise market power. The CalISO contends that Mirant fails to acknowledge the ability of entities in supply-constrained markets to influence prices by offering capacity at prices far in excess of marginal costs. The NCPA states that the Commission's "hub & spoke" test for market power is inadequate in a dynamic wholesale electricity market. The CalISO agrees, and proposes that market participants be granted conditional market based rate authority based on the hub & spoke, and be accountable to additional conditions when market monitoring shows the price cost mark up index over a sustained period of time exceeds an acceptable threshold.

Both NCPA and Mirant argue that the entity monitoring the California electricity markets be independent from the CalISO. The CalISO agrees that the market monitor should be independent; however, the CalISO does not believe that such an entity must be separate form an independent system operator. The CalISO believes that its thorough understanding of the current operating practices and procedures would be of benefit to the market monitor, and that this type of understanding would be extremely difficult to acquire if the market monitor were external to the CalISO.

The Modesto Irrigation District

Modesto believes that the adoption of the CalISO's Available Capacity Reserve (ACR) proposal will lead to inefficiencies and impose excessive costs onto ratepayers. Modesto requests that the Commission reject the CalISO's ACR proposal.

Calpine Corporation

Calpine's comments focus primarily on the proposals presented by the Department of Market Analysis of the CalISO, the Market Surveillance Committee of the ISO (MSC Proposal) and the Joint Market Monitoring and Market Power Mitigation Proposal of Mirant, Reliant, Duke Energy, and Williams (Generators). Calpine generally supports the joint proposal sponsored by the Generators, which, calls for an Independent Market Monitoring Unit (MMU), recommends monitoring procedures used by other ISO's, particularly in the PJM market, and emphasizes the need for the MMU to address structural problems via recommendations presented to the CalISO and to identify specific instances in which rules have been violated or market power abused. Calpine believes that the pricing mechanism for forward contracts should take into consideration other variables which affect pricing, including emission costs, opportunity costs and various operating constraints. Next, whatever mitigation measures are adopted should apply to new generation capacity, as well as old.