

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Curt Hébert, Jr., Chairman;
William L. Massey, and Linda Breathitt.

San Diego Gas & Electric Company,
Complainant,

v.

Docket No. EL00-95-012

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

Investigation of Practices of the California
Independent System Operator and the California
Power Exchange

Docket No. EL00-98-000

California Independent System Operator
Corporation

Docket No. RT01-85-000

Investigation of Wholesale Rates of Public Utility
Sellers of Energy and Ancillary Services in the
Western Systems Coordinating Council

Docket No. EL01-68-000

ORDER ESTABLISHING
PROSPECTIVE MITIGATION AND MONITORING PLAN
FOR THE CALIFORNIA WHOLESALE ELECTRIC MARKETS
AND ESTABLISHING AN INVESTIGATION OF PUBLIC
UTILITY RATES IN WHOLESALE WESTERN ENERGY MARKETS

(Issued April 26, 2001)

In this order, the Commission adopts a market monitoring and mitigation plan for the California market to replace the \$150/MWh breakpoint plan adopted in its

December 15, 2000 order.¹ The mitigation plan adopted here, which will be in place for a period not to exceed one year, will: (1) increase the coordination and control of outages, (2) require sellers with participating generator agreements to offer all their available power in real time, (3) require load serving entities to establish demand response mechanisms in which they will identify the price at which load should be curtailed, (4) establish a single market clearing price auction for the real-time market, and (5) establish price mitigation for available capacity in real time when there is a reserve deficiency during emergency stages beginning with stage 1. In addition, this mitigation plan is conditioned on the California ISO and the three investor owned utilities (IOUs) filing a regional transmission organization (RTO) proposal by June 1, 2001.

Under section 206 of the Federal Power Act (FPA), the Commission also is instituting an investigation into the rates, terms and conditions of public utility sales for resale of electric energy in interstate commerce in the WSCC other than sales through the California ISO markets, to the extent that such sales for resale involve: (1) electric energy sold in real-time spot markets (i.e. up to 24 hours in advance); and (2) take place during conditions when contingency reserves (as defined by the WSCC) for any control area fall below 7 percent.

I. Background

In an order issued August 23, 2000,² the Commission instituted formal hearing proceedings under section 206 of the FPA to investigate the justness and reasonableness of the rates for energy and ancillary services of public utility sellers into the California ISO and PX spot markets, and also to investigate whether the tariffs, contracts, institutional structures, and bylaws of the ISO and PX were adversely affecting the wholesale power markets in California. These proceedings were intended to investigate the significant increases in the prices for energy and ancillary services in the California market.

In the December 15 Order, the Commission found that the market structures and rules for wholesale sales of electric energy in California were seriously flawed and that these structures and rules, in conjunction with an imbalance of supply and demand in California, have caused, and continue to have the potential to cause, unjust and unreasonable rates for short-term energy under certain conditions. The Commission, therefore, established remedies for the California wholesale electric markets, which included, in part, elimination of the mandatory PX Buy-Sell requirement, establishment of a benchmark price for wholesale bilateral contracts, establishment of penalties for underscheduling load, a

¹San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, 93 FERC ¶ 61,294 (2000) (December 15 Order), reh'g pending.

²San Diego Gas & Electric Company, et al., 92 FERC ¶ 61,172 at 61,606 (2000) (August 23 Order).

requirement for an independent governing board for the California ISO, and a requirement for the filing of generation interconnection procedures.

As an interim measure, the Commission established a \$150/MWh breakpoint under which public utility sellers bidding above the breakpoint receive their actual bids, but are subject to monitoring and reporting requirements to ensure that rates remain just and reasonable, including the potential for having to pay refunds for prices charged above the breakpoint.³ The December 15 Order also required the development of a longer term mitigation plan to replace the interim breakpoint methodology by May 1, 2001.

On January 23, 2001, the Director of the Division of Energy Markets in the Office of Markets, Tariffs and Rates convened a technical conference to develop a plan to replace the interim breakpoint price.⁴ Comments and reply comments were filed with the Commission and posted on its website. On March 9, 2001, Commission Staff issued a recommendation for prospective market monitoring and mitigation for the real-time electric market. The Staff's recommendation recognized that the real solution to California's energy problem lies in increased investment in infrastructure. It also recognized that while mitigation measures should be considered to deal with the current situation, the approach adopted must be consistent with the need to attract new investment and should, to the extent possible, encourage such investment. The Staff recommendation also recognized that, since the December 15 Order, the marketplace in California has changed with greater reliance on bilateral contracts, as opposed to bidding in real-time markets.

The Staff outlined certain core design principles that a good mitigation plan should include: 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; price mitigation should be as surgical (least intrusive) as possible and last for as little time as possible; price mitigation should be as market oriented as possible and adopt market solutions and mechanisms to the maximum extent possible; the pricing provisions must encourage, and not discourage, the critically needed investment in infrastructure (*e.g.*, increasing generation supply, adding required transmission, and implementing demand response).

³On March 9, 2001, the Commission issued an order directing public utility sellers to provide refunds (or offsets to amounts owed) or to provide cost or other justification for prices that exceeded the breakpoint. 94 FERC ¶ 61,245 (2001), *reh'g pending*.

⁴93 FERC ¶ 61,294 at 61,983, 61,996-97.

The Staff recognized that achieving these goals requires difficult choices, and no mitigation approach will provide the perfect answer.⁵ The Staff concluded that the current breakpoint method did not meet these goals, because mitigation was ex post (corrections were made after the fact, potentially altering business arrangements that may have appeared reasonable when made), the review of individual transactions is labor intensive, and market prices above the breakpoint were not transparent.

In place of the breakpoint method, the Staff recommended that the ISO conduct a real-time auction with measures to mitigate the potential exercise of market power through physical or economic withholding. This auction would 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. 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.

Twenty-nine comments were received on this proposal.⁶ While the comments supported certain aspects of the Staff proposal in theory, they also recommended a variety of changes and raised

⁵See *In re California Power Exchange v. FERC*, No. 01-70031, 2001 U.S. App. LEXIS 6153 (9th Cir., April 11, 2001) (recognizing that the \$150/MWh breakpoint approach was an appropriate middle ground).

⁶Those filing comments are listed on Appendix A.

technical issues as to how it would be implemented. The comments focused in particular on the method used for price mitigation and the periods when mitigation would be applied.

In addition, on April 6, 2001, the ISO submitted a proposed market stabilization plan; however, it explained that it was not now submitting the proposed revisions to its tariff that would implement its general plan.⁷ Rather, it indicated that it "is preparing the Tariff revisions necessary to implement the Market Stabilization Plan for filing consistent with the Commission's direction or the outcome of this proceeding."⁸ The Market Stabilization Plan submitted by the ISO is essentially a compilation of earlier proposals by the ISO. The Market Stabilization Plan has two primary goals: cost control and operational stability. With respect to cost control, the plan would require all participating generators to have standing bids for all of their available capacity, subject to resource specific cost-based bid caps, reflecting each resource's cost curve. In return, the participating resources will receive annual availability payments designed to permit recovery of all fixed costs. The plan also includes payments to cover start-up and no-load costs. With respect to operational stability, the ISO indicates that it will propose new forward markets for energy in day ahead and hour ahead markets, the

⁷The ISO stated that it was making this submittal in response to a March 30, 2001 Commission Staff letter in Docket No. EL00-95-012 requesting additional information concerning two studies by the ISO that claimed \$6.2 billion in overcharges. In that letter, Commission Staff noted that the Commission had proposed a May 1, 2001 effective date for the permanent market mitigation plan and suggested to the ISO that if it intended to file a comprehensive Market Stabilization Plan, which the ISO noted in its comment that it planned to file in April, it should do so no later than April 6, 2001, to give the Commission sufficient time to consider it. The Commission also points out that the \$6.2 billion in overcharges overstates the extent of the overcharges related to transactions subject to the Commission's jurisdiction. The ISO alleges in its March 22, 2001, comments to staff's market mitigation proposal that potential costs in excess of competitive levels for the California wholesale market exceed \$6.2 billion for the period May 2000 through February 2001. The ISO now contends that costs in excess of competitive levels now exceed \$6.7 billion due to an additional \$430 million not included in the earlier analysis. However, in response to the March 30, 2001, Commission staff letter in Docket No. EL00-95-012, the ISO notes that approximately \$2.7 billion represents bilateral and self-supply energy scheduled outside of the PX and ISO markets. Of the remaining \$4 billion, approximately \$3.1 billion is subject to FERC jurisdiction. However, \$1.8 billion occurred prior to October 2000. What remains in dispute is \$1.3 billion for the period October 2000 through February 2001. There are two distinct differences between the ISO's calculation of excess charges and the Commission's \$124 million refund calculation for January and February 2001. The ISO includes the October through December 2000 period while the Commission has, to date, focused on January and February 2001. In addition, the ISO included every hour in its refund calculation while the Commission calculated refunds for the hours when a Stage 3 was in effect.

⁸ISO April 6, 2001 Submittal at 5.

implementation of a new transmission constrained unit commitment economic dispatch program, the implementation of new congestion management procedures, and the ability to curtail exports.

A number of comments were filed on the Market Stabilization Plan, some supporting it, others questioning it and raising questions about the authority of the ISO to make such a filing in light of the Board's lack of independence and its failure to comply with Commission orders.⁹

II. California Monitoring and Mitigation Plan

In the December 15, 2000 order, the Commission directed staff to convene a technical conference to develop a monitoring and mitigation plan for realtime energy markets to replace the interim \$150/MWh breakpoint plan with a realtime mitigation plan that would not rely on a refund condition.¹⁰ In this order, the Commission is modifying the \$150/MWh breakpoint to provide for prospective mitigation, ongoing monitoring, and the development of demand response mechanisms.

In examining monitoring and mitigation plans for the real-time market, it must be recognized that there are no perfect plans. Any mitigation plan is likely to create different incentives for both sellers and buyers.¹¹ In establishing the mitigation plan described below, the Commission was guided by several goals. It sought to develop a plan that addresses the need for mitigation in as market-oriented a manner as possible. It also sought to create a plan that would not discourage the critically needed investment in new generation and transmission as well as development of greater demand response to send proper demand pricing signals.

Some of the power suppliers maintain that no mitigation plan should be adopted, and that the Commission should instead rely solely on market forces. However, the Commission found in the December 15 Order that, because of the flawed market rules and structures in place, there was a potential for the exercise of market power in the California spot market under certain conditions and that a mitigation plan, therefore, was necessary. The Commission will not reconsider that determination here.

⁹The Commission will address compliance with the ISO governance provisions of the December 15 Order in a subsequent order.

¹⁰See 93 FERC ¶ 61,294, at 62,011.

¹¹Under the Federal Power Act, the Commission must protect both consumers and investors. See *FPC v. Hope*, 320 U.S. 591, 601-605 (1944).

The Commission's monitoring and mitigation plan for the real-time market incorporates portions of the recommendations made by Staff as well as portions of the mitigation plan used in the March 9, 2001 order.¹² The fundamental principles of this plan are to:

Enhance the ISO's ability to coordinate and control planned outages in the real-time market during all hours.

Require sellers with PGAs as well as non-public utility generators located in California, that make sales through the ISO's markets or that use the ISO's interstate transmission grid (with the exception of hydroelectric power), to offer all their available power in real time during all hours.

Require public utility load serving entities to submit demand bids (identifying the price at which load will be curtailed) in the real-time market during all hours.

Establish conditions, including refund liability, on public utility sellers' market-based rate authority to prevent anticompetitive bidding behavior in the real-time market during all hours.

Require the ISO to submit weekly reports on schedule, outage, and bid data for all hours so that Commission staff can continue to monitor generating unit outages and real-time prices.

Establish a mechanism for price mitigation for all sellers (excluding out-of-state generators) bidding into the ISO's real-time market during a reserve deficiency, defined as reserves of 7.5 percent or less. Under this mechanism, the Commission is establishing a formula (based on gas fired generation) that the ISO can use to establish the real-time market clearing price when mitigation applies.

This monitoring and mitigation plan will become effective May 29, 2001. The \$150/MWh breakpoint and the refund approach established in the March 9, 2001 order will remain in effect until then. In addition, the Commission is requiring the ISO to file with the Commission periodic reports on this monitoring and mitigation plan as well as progress that is being made in developing new generation and demand response.

The monitoring and mitigation plan adopted here will terminate not later than one year from the date of this order. According to Governor Davis' press release of April 4, 2001, the California Energy Commission's current status report indicates that new generation totaling 4,168 MW will be on line by the end of August 2001 and there could be as much as 6,879 MW on line for the summer of 2002. In

¹²San Diego Gas & Electric Co., et al., . 94 FERC ¶ 61,245 (2001), reh'g pending.

addition, in a year, the retail demand response mechanisms required by this order should be fully in effect.

In addition, this mitigation plan is conditioned on the California ISO and the three investor owned utilities (IOUs) filing an RTO proposal by June 1, 2001, consistent with the characteristics and functions in Order No. 2000. This condition recognizes that the only real solution to supply problems that affect the western United States is to create a regional response.

The mitigation plan adopted here seeks to reasonably balance the interests of suppliers and consumers of energy in California's wholesale markets to mitigate the dysfunctional market without delaying needed investment in generation, transmission, and demand response mechanisms. This plan seeks to achieve mitigation by emulating a competitive marketplace. The plan seeks to foster greater coordination of outages to ensure that supply is available and to make sure that available supply is bid into the market. It further seeks to create the demand side response which would occur in a competitive market. During periods of reserve deficiencies and the potential for unjust and unreasonable prices exists, the plan permits the ISO to use market prices for inputs (*e.g.*, natural gas and emissions credits) to establish bids. This approach is consistent with bidding that would occur in a competitive market clearing auction in which each supplier has the incentive to bid competitively at its marginal costs. The Commission will discuss each element of the plan below.

A. Coordination and Control of Outages

To ensure that sufficient generation capacity is available to meet anticipated market needs, it is important for the ISO and generators to work cooperatively to schedule generating unit maintenance and outages in ways that will provide sufficient energy resources when needed while also providing for reliable plant operation. In its April 6 submittal, the ISO specifically supports the Staff's proposal that "California generator outages should be more closely coordinated and that questionable outages be reported and investigated."¹³ The ISO indicates that the state of California is considering legislation that would implement the coordination of outages and the adoption of generating unit maintenance standards. In this regard, the ISO indicates that it anticipates submitting a tariff filing in the near future to implement a broader coordination of generator planned outages in California.¹⁴ The ISO, therefore, will be required to make a tariff filing within 15 days of this order proposing a mechanism for coordination and control of outages, including periodic reports to the Commission, consistent with the discussion in this order. The ISO must serve these tariff changes on all PGA customers. The comments will be due five days after that filing.

¹³April 6 Submittal at 35.

¹⁴*Id.* at 36.

The comments filed in this proceeding generally favor better coordination of plant maintenance. The parties raise questions only as to how such coordination is intended to work and how problems will be resolved. The CPUC maintains that unless a generator has been scheduled for maintenance, the risk of forced outages should be placed on generators, not on the ISO. According to the CPUC, a generator that is scheduled to run but which goes down, should be responsible for replacing the energy its outage has required the ISO to purchase.

On the other hand, generators and others¹⁵ are concerned that the ISO is politicized and will abuse its authority and improperly deny maintenance. They contend that the ISO should be responsible for paying generators' costs if the ISO denies maintenance. The Northern California Power Agency argues that imposing penalties for failure to run is particularly problematic for load serving entities who have no incentive to manipulate an outage since they have to pay for replacement power to serve their own load. Duke Energy, EPSA and Independent Energy Producers contend that the Commission should appoint an independent agency to conduct standardized inspections and review ISO determinations.

The ISO must be provided the authority 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 must be approved by the Commission. The Commission has monitored outages and will continue to do so.¹⁶ The ISO must continue its daily and weekly reports to the Commission on outages. It also must alert the Commission immediately when disputes arise over planned outages, so that such disputes can be expeditiously reviewed. In addition, unplanned outages must continue to be closely monitored by the ISO and questionable outages should be immediately reported to the Commission.

The Commission intends for the ISO's requirements to foster cooperation rather than establish punitive provisions either penalizing generators or the ISO. The ISO, if truly independent,¹⁷ should have little incentive to deny necessary maintenance requests since any such action could exacerbate the supply shortage in California by causing unplanned and lengthy generating unit outages. Equally, the ISO in formulating its policies and procedures has to recognize that generating units may go down unexpectedly, particularly during periods when the existing older generating units are being asked to run for exceedingly long periods and at high levels.

¹⁵See Comments by Duke Energy, Mirant, Morgan Stanley, PG&E, Reliant, Williams, Enron Power Marketing.

¹⁶See Commission Staff, Report on Outages in the State of California (Feb. 1, 2001), <http://www3.ferc.fed.us/bulkpower/bulkpower.htm>; AES Southland, Inc., 94 FERC ¶ 61,248 (2001).

¹⁷As discussed earlier, the Commission will address allegations about the ISO's lack of independence and its governance procedures in a later order.

B. Selling Obligations

The Commission will require those generators with PGAs to offer the ISO all of their capacity in real time during all hours if it is available and not already scheduled to run through bilateral agreements. This must-offer obligation is designed to ensure that the ISO will be able to call upon available resources in the real-time market to the extent that energy is needed. The basis for this requirement is that, under competitive conditions, a generator that has available energy in real time should be willing to sell that energy at a price that covers its marginal costs, since it has no alternative purchaser at that time.

Some of the comments suggest that the mitigation plan should not be limited to generators signing PGAs, as proposed by the staff, but should be expanded to include all generators.¹⁸ The Commission agrees that all generators need to participate in helping to solve the problems in California. Accordingly, the Commission will require that, as a condition of selling into the ISO markets which are subject to this Commission's exclusive jurisdiction, all sellers that own or control generators located in California, including non-public utility sellers that own or control generators in California, must abide by the same must-offer obligation and the price mitigation plan, including the filing of heat and emissions rates, described in this order. The ISO is directed to modify its energy tariffs to reflect this condition. While the Commission does not directly regulate the non-public utility sales for resale through the ISO, it has the authority, and indeed the responsibility, to ensure that the ISO tariffs covering spot market energy sales result in just and reasonable rates. However, the Commission cannot ensure such just and reasonable rates in the current circumstances in California unless all entities that sell energy through the markets operated by the ISO abide by the same conditions. The Commission, therefore, concludes that it is necessary to impose this condition.

In addition to the above condition on sales through the energy markets operated by the ISO, we also will require that, as a condition of using the ISO's open access interstate transmission tariff which is subject to this Commission's exclusive jurisdiction, all sellers of energy that own or control generators in California, including non-public utilities, whose power is transmitted over the ISO-controlled interstate transmission facilities, must abide by the same must-offer obligation and the price mitigation plan, including the filing of heat and emissions rates, described in this order. Since transmission constraints are contributing to the problems in California, non-public utility generators should not be able to avail themselves of the use of the public utility ISO-controlled transmission facilities while not committing themselves to help solve the problems that have arisen. Including non-public utility generators in California as part of the mitigation will not only help ensure that jurisdictional rates for power sales are just and reasonable but will also help to maintain the reliability of the interstate

¹⁸See Comment by Dynegy.

grid.¹⁹ Thus, non-public utility generators in California that utilize the ISO-controlled transmission grid to effectuate purchases for resale or sales for resale of energy will be subject to this condition. The ISO is directed to modify its open access transmission tariff to reflect the condition. Finally, given the importance of non-public utilities to the market, the Commission also encourages the non-public utilities to participate in a West-wide RTO.

Several commenters²⁰ are concerned about generators avoiding the must-offer requirement. They raise concerns about so-called "megawatt laundering" where a supplier schedules supply out-of-state and then reimports that power to avoid a mitigated price. They also contend that imports must be included in the proposal to cap prices for all sales into the ISO market, not just sales made by PGA generators.²¹

The Commission recognizes that the California market is integrated with those of other states, and for that reason, is instituting an investigation into public utility sales for resale in the WSCC. In addition, as discussed above, to ensure that the mitigation and monitoring proposal is applied equally to all generators in California, the must-offer obligation will be applied to include non-public utility generators in California which currently make use of the ISO's interstate transmission grid.

Generators are also concerned with how the must-offer obligation will affect those with energy-limited resources. For instance, some ask how the must-offer will apply to hydroelectric power, since this resource has a temporal component and generators will want to use the resource when the prices

¹⁹While the Commission has not previously used its jurisdiction over public utility interstate transmission lines to ensure that non-public utility generators contribute to the solution of problems in California, the Commission has the authority to impose conditions on the use of interstate facilities owned, operated or controlled by public utilities such as the ISO, and on the tariffs under which those public utilities provide service. *See* Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000) (conditioning a non-public utility's use of a public utility's open access transmission service on the non-public utility providing reciprocal transmission service to the public utility); *American Gas Association v. FERC*, 912 F.2d 1496, (D.C. Cir. 1990) (conditioning the use of open access transportation on agreement to credit revenues against take-or-pay obligations). *See also* *FPC v. Louisiana Power & Light Co.*, 406 U.S. 621 (1972) (curtailment plans can apply to non-jurisdictional customers); *FPC v. Transcontinental Gas Pipe Line Corp.*, 365 U.S. 1 (1961) (denial of certificate to pipeline for non-jurisdictional transportation); *Mississippi River Transmission Corp. v. FERC*, 969 F.2d 1215 (D.C. Cir. 1992) (condition on certificate requiring that non-jurisdictional customers be charged no less than maximum transportation rate).

²⁰*See* Comments by ISO, ISO MSC, California Commission, SMUD, County of San Diego, San Diego Gas & Electric, SoCal Edison.

²¹*See* Comment by Dynegey.

are the highest.²² A similar concern is raised with respect to generation units that can only be run for a limited duration.²³ Mirant contends such units cannot be forced to run after their operational limits are reached. It also contends that these units have an incentive to run when prices are highest, and that it will incur opportunity losses if forced to run at less lucrative times or if its bids cannot reflect opportunity costs. The Northern California Power Agency raises the same questions about municipal generators, contending that they need to be able to choose the periods in which they run given the needs of their own electric load. The Western Power Trading Forum and Duke Energy contend that the Staff's proposal is discriminatory because it applies only to a limited segment of the market (the divested generators) that have signed PGAs and does not apply to other generators, such as municipal utilities.

Under the must-offer obligation, no generator will be required to run in violation of its certificate or applicable law. The Commission, however, recognizes the difficulty in applying the must-offer requirement to hydroelectric power, because of its multi-purpose limitations (e.g., irrigation, recreational, and power production), and therefore will exempt them from the must-offer obligation. The Commission, however, will not exempt gas-fired resources from the must-offer obligation, simply because they may have environmental limitations. The question of whether units can run outside of their prescribed limits, and the costs imposed as a consequence, are within the control of the state. As discussed later, the mitigation proposal will include procedures to enable generators to recover costs incurred from running outside of their environmental limitations.

Mirant, Duke Energy, and PG&E also raise the question of how to handle the generator's decision to withhold capacity to cover the eventuality of a unit tripping off-line. If generators cannot reserve power, Mirant argues they should be permitted to increase bids to cover the risk.

The purpose of the Commission's must-offer obligation is to ensure that all units that are able to run but are not already scheduled to run (with the exception of hydroelectric power, as discussed above) are in fact made available to the ISO in the real-time market. In forward markets, a generation owner may not want to commit all of its capacity to forward transactions, given the possibility that one or more of its units could trip off line and leave the owner without sufficient capacity to cover these commitments. However, when the time comes for bids to be submitted in the real-time market, all available generation (not scheduled or committed to bilateral agreements) must be offered in the real-time market. A generator should not withhold capacity or increase its bid to cover the risk that its unit may trip off-line between the time it submits its real-time bid and real-time dispatch, because the generator faces no financial risk for such an outage. If no unit suffers an outage, the generator will receive the market clearing price for all the units it bids into the market. However, if a unit goes out, the generator will still receive the market clearing price for the unit (that it would have withheld) that is

²²See Comments by Enron Power Marketing, Metropolitan Water District, Cal. Dep't of Water Resources.

²³See Comments by PG&E.

running, which will offset the cost of paying for replacement power for the unit suffering the outage. Thus, the generator is in no different position than if it kept one unit idle in the first place, in which case it would not be paid the market clearing price for energy for that unit.

C. Demand Response

Beginning on June 1, 2001, the Commission will require each public utility purchasing electricity in the ISO's real-time market to submit demand-side bids that will indicate the price at which load will be curtailed and will identify the load to be curtailed. The bids will indicate the maximum prices that the purchaser is willing to pay for specified amounts of electricity and the loads on its system that would be curtailed when the applicable real-time energy price exceeds its bid.²⁴ The ISO will be required to curtail service to the entity in accordance with its bids.

These requirements will develop demand-side price responsiveness that will help mitigate market power and lessen the severity of price spikes. When demand responds to price, suppliers have additional incentives to keep bids close to their marginal production costs, because high bids are more likely to reduce the bidder's energy sales. Thus, demand-side bidding applies downward market pressure on prices. Demand-side price-responsive bids will also help to allocate scarce supplies efficiently. Without the development of price-responsive bids, the allocation of short supplies – through rolling blackouts – is arbitrary and inefficient. In order for the market to function effectively, there must be a mechanism to allocate short supplies to those who value energy the most, while encouraging those with lower-cost alternatives to take advantage of them. Customers need to be able to respond to price signals so that those facing more elastic demands can relinquish power to those placing greater value on obtaining power at that time. For example, a load serving entity serving a retail customer with back-up power needs to have appropriate price signals to determine whether the back-up source should be used. An industrial plant also could agree to close during certain hours, or blocks of hours, during the day, allowing its load serving entity to reduce real-time purchases from the ISO.

Demand response can also be developed by establishing a western-wide program under which energy users (such as industrial plants) outside of California could be paid for curtailing power to be used in California.²⁵ This could be accomplished by having the customer voluntarily submit a bid for

²⁴The Commission has required the ISO to adhere to the creditworthiness provisions of its tariff. California Independent System Operator Corp., 94 FERC ¶ 61,132, *reh'g denied*, 95 FERC ¶ 61,026 (2001). The ISO, therefore, should take into account a buyer's creditworthiness in determining what bids it is financially capable of honoring.

²⁵The Commission has already taken action to expedite the inclusion of a demand response mechanism. Removing Obstacles to Increased Electric Generators and Natural Gas Supply in the Western United States, 94 FERC ¶ 61,272 (2001) (streamlining filing and notice requirements for

demand reduction (or interruption), and, if that bid is accepted, the customer would have its power transferred to a deficit control area, and be paid for their load curtailment.

The Oversight Board maintains that, while the ISO should accommodate bids to curtail loads, load serving entities should not be required to state a price at which loads will be curtailed, contending this is a prerogative of the state. The ISO and others contend that there is a limit to the extent to which load can be curtailed, and they are already implementing as many programs as they can.

State authorities can promote demand-side price responsiveness in several ways, such as allowing retail rates to vary to reflect wholesale prices, facilitating the necessary metering, and adopting conservation programs. While the design of retail rates is a matter of state jurisdiction, the requirements adopted here do not intrude upon state retail rate design. Instead, they bear upon the development of prices in the ISO's markets and the rules governing how sellers and buyers act in those markets, over which the Commission has jurisdiction.

The Commission has concluded that it is necessary to require public utility load serving entities to submit demand bids and that demand side bidding should begin June 1, 2001. Although retail demand response may not be fully developed by that time, there are some efforts in effect now and this requirement will support those efforts. The Commission fully expects that price responsiveness of load serving entities will increase over time as retail programs develop and additional metering is installed to allow retail customers to respond to prices. The wholesale requirement for demand side bidding will, therefore, be in place to support those efforts. Moreover, as discussed above, requiring demand side bidding will provide downward pressure on wholesale prices since sellers will recognize the ISO will not pay any price to obtain power.

D. Price Mitigation in the Real-time Auction During Reserve Deficiencies

1. Mitigation Approach Adopted by the Commission

a. Market Clearing Auction

The Commission will require the ISO to establish a market clearing auction for real-time markets with the following characteristics. As part of that auction, the Commission will require price mitigation for all generators in California, including non-public utility generators, with available capacity during periods of reserve deficiency, defined as emergency situations beginning at stage 1 (i.e., when reserves are 7.5 percent or less). This mitigation is based not on inflexible price caps, but on the use of competitive bids in the ISO auction to replicate competitive pricing. The mitigation applied here is a

²⁵(...continued)
demand reductions).

variant of the proposal made by staff and the proxy mitigation used by the Commission in the March 9, 2001 order and implemented in subsequent notices.

Commission staff had proposed that each generator submit to the ISO a formula based on heat rate, gas costs, and emission credits by which the ISO could calculate a marginal cost for each unit. Under staff's approach, during periods of reserve deficiency, the ISO would then use the marginal cost prices to determine the market clearing price in the auction. The Commission is concerned that this approach will be too difficult to administer as it requires review of marginal cost information provided by each generator.

Instead, the Commission is adopting a mitigation plan in which each gas-fired generator in California (both those signing PGAs and covered non-public utility gas-fired generators) will file with the Commission and the ISO (on a confidential basis) the heat rate and emission rate for each generating unit. These heat rates must reflect operational heat rates that do not include start-up and minimum load fuel costs because, in a declared emergency, the market clearing price should reflect the cost to generate at or near maximum outputs. The ISO will use these heat rates to calculate a marginal cost for each generator by using a proxy for the gas costs, emission cost, and a \$2.00 adder for operation and maintenance expenses. The gas cost proxy will use an average of the daily prices published in Gas Daily for all California delivery points. The emission cost will be calculated by the ISO using emissions costs from Cantor Fitzgerald Environmental Brokerage Services and the emissions rate for the unit.²⁶ The ISO will publish by 8:00 am, the gas and emission figures to be used for the next day in any hour where an emergency is declared. These figures will be based on the prior day's Gas Daily and Cantor Fitzgerald data. In the event that prior day figures are not available, the ISO is to use the most recent data available. The ISO's auction will be modified to permit the generators to elect the proxy price in lieu of an individual bid above the proxy. All generators who elect the proxy will be paid a single market clearing price reflecting the highest priced unit dispatched calculated using the proxy prices.²⁷

It may be that for some gas-fired generators in California, the proxy bid calculated by this method is lower than the generator's actual marginal costs because its true gas costs are higher than the proxy gas costs or it has incurred emission penalties or other costs greater than those assumed in the proxy. In those cases, the generator may submit a bid greater than that calculated through the proxy. If that bid is accepted, the generator will be paid what it bid, subject to refund and justification. A generator's non-proxy bid will not establish the market clearing price. However, to the extent a

²⁶San Diego Gas & Electric, 94 FERC ¶ 61,245, at 61,863 (2001), reh'g pending.

²⁷In order for this price mitigation to begin on May 29, 2001, the ISO is required to publish the applicable Gas Daily Price and Cantor Fitzgerald emission's price on May 28, 2001.

generator submits at or below the market clearing price, it will receive the market clearing price and will not be subject to refund liability.²⁸

California generators that do not use natural gas can accept the market clearing price calculated by the ISO during emergency situations. If such generators believe their costs are higher than the market clearing price, then they can submit a higher bid, which they will be paid if the bid is accepted, subject to refund and justification.

At the end of each month in which a generator submits a bid higher than the market clearing price, the generator must file with the Commission and the ISO, within seven days of the end of the month, its complete justification, including a detailed breakdown of all of its component costs, for each transaction exceeding the market clearing price established by the proxy bid. This justification must be based on a showing of actual marginal costs higher than the market-clearing price.²⁹ The refund obligation will end 60 days from the date of each such filing, unless the Commission, within that period, notifies the seller otherwise.

Recognizing that California is a net importer of energy in a regional market that will suffer generally tight supplies, the mitigation plan must strike a balance between constraining price and encouraging more supply.³⁰ Consequently, bids must be accepted from resources located outside California, and these bidders, if dispatched, can elect to be paid the market clearing price or can submit their own bid price. If they submit their own bids, such bids will not be used in setting the market clearing price during mitigated periods.

As staff noted in its recommendations, applying marginal cost mitigation to marketers would be extremely difficult. Marketers generally have a portfolio of energy supplies and often sell energy numerous times. It, therefore, would be exceedingly difficult to try and trace energy back to the generating source to determine the heat rate of the source. Indeed, if multiple sources are used, one could not isolate which source provided the power for the marketer's bid. Accordingly, during

²⁸However, all public utility rates will be subject to refund for violations of the conditions imposed on market-based rates, discussed infra.

²⁹As explained below, generators will not be permitted to include an extra cost component to represent scarcity rents since such rents are provided through payment of the market clearing price. Nor will they be permitted to include a cost component to represent opportunity costs, because power that is available in the real-time market cannot be sold elsewhere. See text accompanying note 46, infra.

³⁰See In re California Power Exchange v. FERC, No. 01-70031, 2001 U.S. App. LEXIS 6153 (9th Cir., April 11, 2001) (recognizing need to limit mitigation based on realization that competition must exist for the California energy market to survive in the long run).

mitigation, marketers can accept the market clearing proxy price or submit their own bid. If their bid exceeds the market clearing price, they would be required to justify the bid based on the prices they paid for power.³¹

b. Conditions on Market-Based Rate Authority

In addition, the Commission is conditioning public utility sellers' market-based rates to ensure that they do not engage in certain anticompetitive bidding behavior. Suppliers violating these conditions would have their rates subject to refund as well as the imposition of other conditions on their market-based rate authority.

First, bids that vary with unit output in a way that is unrelated to the known performance characteristics of the unit are prohibited. An example of this bidding practice is the so-called "hockey stick" bid where the last megawatts bid from a unit are bid at an excessively high price relative to the bid(s) on the other capacity from the unit. A variant of this pattern could be a single unit in a portfolio that is bid at an excessively high level compared to the remainder of the portfolio, without any apparent performance or input cost basis.

A second category of prohibited bids are those that vary over time in a manner that appears unrelated to change in the unit's performance or to changes in the supply environment that would induce additional risk or other adverse shifts in the cost basis. An example of this is a bid that appears to change only in response to increased demand or reduced reserve margins, particularly if the timing of the bid is related to public announcements of system conditions or to timing of outages in a participant's portfolio.

Should public utility market participants engage in any of the prohibited behavior discussed above, their rates will be subject to increased scrutiny by the Commission and potential refunds. This could result in further conditions or restrictions on their market-based rate authority, including prospective revocation of market-based rate authority.

c. Monitoring Requirements

³¹As discussed before with respect to generators, marketers, and all other sellers, will not be permitted to include extra cost components for scarcity rents or opportunity costs. See note 28, supra, and text accompanying note 46, infra.

The Commission also is establishing a monitoring requirement to enable it to keep better track of the developments in the California market. The ISO will be required to submit weekly reports to the Commission of schedule, outage, and bid data from the ISO to keep the Commission informed on the current market performance. If the ISO detects possibly inappropriate bidding behavior, the ISO should identify the concerns in its weekly report. In addition, the Commission staff will continue its independent monitoring of generating unit outages as well as the real-time and forward price monitoring of both electric and natural gas commodity and transmission prices. 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 the key elements of the mitigation plan, such as the level of unplanned outages and conditions that could cause price mitigation to be invoked.

2. Comments

The comments on the staff recommendations focused on three aspects of mitigation: when mitigation is to be applied; how the mitigated prices will be determined; and how marginal costs will be calculated. Since these comments are still relevant to the mitigation plan adopted by the Commission even though it deviates from the staff's proposal, the Commission will address the comments below.

a. When Price Mitigation is Applicable

The Staff proposed that price mitigation be imposed during periods of reserve deficiency, citing Stage 3 emergencies as an example. The generators support a limitation to Stage 3 emergencies, but many other commenters oppose a limitation to Stage 3 emergencies, arguing price mitigation should apply at all times in the spot market.³² These commenters maintain that, under the FPA, once the Commission has made a finding that prices are unjust and unreasonable as it did in the December 15 Order, the Commission can no longer rely on market-based rates. They contend that the record shows that market power can be exercised during periods other than Stage 3 emergencies. For instance, the ISO contends that it has a responsibility to use all available resources to buy power to avoid going into any emergency stage and that, therefore, market power can be exercised at all times. It further contends that application of price mitigation only to Stage 3 emergencies will send improper price signals, since high prices may be justified during peak (scarcity) conditions, but during off-peak periods, high prices represent the exercise of market power. In its Market Stabilization Plan, the ISO has proposed a comprehensive plan to regulate prices in all time periods.

³²See Comments by Arizona Residential Consumers, ISO, California Department of Water Resources, CMUA, County of San Diego, San Diego Gas & Electric, SMUD, City of San Diego, Southern California Water Co., CA Electricity Oversight Board, Northern California Power Agency.

The Commission will make price mitigation applicable to all conditions defined by the ISO as beginning when reserves fall below 7.5%. These conditions, although applied for purposes of reliability, nevertheless can serve as a standard by which the market should have enough supply to yield a competitive result. Ordinarily, in a competitive market with demand response, high prices during times of reserve deficiency would be legitimate scarcity rents needed to properly allocate energy to those placing the highest value on obtaining energy. However, given the lack of demand responsiveness in this market, when the market realizes that reliability targets are missed, suppliers have a greater incentive to offer supply at prices above what they would ordinarily bid in a competitive market. Under these conditions, all suppliers are aware of how tight supplies are relative to the amount they have to offer, and have an incentive to set a high bid price. Because of the lack of demand response, these prices may not reflect what the market would have established as appropriate scarcity rents and, therefore, may not be just and reasonable.

Once the ISO enters an emergency situation, supply is short relative to demand, demand response is not significant, and the ISO is charged with the responsibility to acquire all available power. In these circumstances, prices may exceed those that would be charged in a competitive market. But these situations are limited to emergency situations. During non-emergency conditions, a supplier has less of an incentive to bid a high price, because it cannot be sure it will be dispatched, since it runs the risk that other suppliers will offer lower bids. In addition, limiting price mitigation to emergency conditions will limit the incentive for generators to withhold capacity in other than emergency conditions. A generator that physically withholds capacity to raise price runs the risk that its withholding of capacity will force an emergency condition in which price mitigation will apply.³³ For these reasons, applying price mitigation to emergency conditions is sufficient to assure just and reasonable rates under the FPA.

Commenters further contend that the Commission's price mitigation should extend beyond real-time markets to day-ahead and hour-ahead markets that the ISO is in the process of developing and even to bilateral markets.³⁴ They maintain that generators with market power will enter into long-term bilateral contracts only if those contracts reflect the market power the suppliers possess.³⁵ They support the mandatory forward contracting plan of the ISO MSC. Generators, on the other hand, contend that invoking a price mitigation plan will create incentives for buyers to avoid entering into bilateral contracts in order to obtain the mitigated prices under the plan.

³³As discussed earlier, the demand response requirement also limits the incentive for a generator to economically withhold capacity by bidding a high price, because if the generator bids a high price, it may not get dispatched at all if its price exceeds the demand bid.

³⁴See Comments by California Commission, San Diego Gas & Electric, ISO Market Surveillance Committee.

³⁵See Comment by ISO Market Surveillance Committee.

This proceeding was established in the December 15 Order to address whether a price mitigation plan was needed to replace the \$150/MWh breakpoint price methodology. The findings as to the need for such price mitigation in the December 15 Order addressed only real-time and spot markets of the ISO and PX. It did not address price mitigation with respect to bilateral markets, which is beyond the scope of this proceeding.

Moreover, the price mitigation plan adopted here will influence other markets, such as the bilateral market, and should not create incentives for buyers to avoid bilateral agreements. Energy buyers are subject to a maximum penalty of \$100/MWh if they have over 5 percent of their load served in the real-time market.³⁶ Under this price mitigation plan, a buyer that fails to negotiate bilateral contracts and attempts to rely on mitigated prices in the real-time market will face the prospect of paying the highest bid price or mitigated marginal cost price plus the \$100/MWh penalty. On the other hand, an energy supplier faces the prospect that it may receive only the mitigated marginal cost price in the real-time market if it does not reach agreement on a bilateral contract. Buyers and sellers, therefore, have an incentive to reach agreement in bilateral contracts somewhere in between the buyer's price exposure (marginal cost price plus \$100/MWh) and the expected marginal cost price.³⁷

Some commenters contend the Commission needs to expand price mitigation to the entire western market, because price mitigation limited to California alone can create adverse incentives.³⁸ For example, SMUD contends that imposing price mitigation only on California may create incentives for out-of-state generators to avoid the California market, thereby exacerbating supply shortages.

Because western markets are interconnected, the Commission recognizes that regional solutions are a necessary part of any long term restructuring of the western marketplace. For that reason, the Commission is requiring the ISO and the three IOUs to file an RTO proposal by June 1, 2001. In addition, as discussed later, the Commission is instituting an investigation into public utility sales for resale in real-time spot markets in the entire WSCC.

³⁶On April 6, 2001, the Commission deferred action on the request by SoCal Edison and PG&E to suspend the penalty for underscheduling. Southern California Edison, 95 FERC ¶ 61,025 (2001).

³⁷See *In re California Power Exchange v. FERC*, No. 01-70031, 2001 U.S. App. LEXIS 6153 (9th Cir., April 11, 2001) (recognizing that Commission has discretion to limit mitigation based on realization that competition must exist for the California energy market to survive in the long run).

³⁸See Comments by County of San Diego, Metropolitan Water District, PG&E, SMUD.

Generators further suggest that the ISO will have an incentive to declare emergency conditions to invoke mitigated prices, rather than because supply and demand conditions dictate.³⁹ The WSSC establishes standards for reserve requirements, as well as reporting requirements, and the ISO must observe those standards in declaring emergencies. The Commission also is requiring the ISO to file weekly reports with the Commission, so that the Commission will have information available to review the ISO's actions.

San Diego Gas & Electric suggests that one method of ensuring that mitigated rates do not interfere with incentives to develop new generation is to exempt new generation from the price mitigation requirement. Since the Commission's price mitigation plan establishes competitive market clearing prices, there may be no need to exempt new generation in order to ensure that they retain an incentive to build new power plants and exempting them could potentially impact prices. Although the Commission has in the past exempted new generation from price mitigation requirements, such exemptions can result in bifurcated markets and market distortions.⁴⁰ The Commission, therefore, will not require the ISO to exempt new generation from the price mitigation requirement.

b. Use of Marginal Costs as the Mitigation Rate

A number of comments suggest the Commission calculate the mitigation rate in other ways, such as using variable cost-based bid caps⁴¹ with each supplier receiving its bid price or traditional cost-of-service rates for each entity, including fixed and variable cost recovery.⁴² The Market Stabilization Plan filed by the ISO also suggests that rates be set using resource specific bid caps as well as additional payments to permit recovery of fixed costs as well as start-up and no load costs. The ISO, however, would pay each generator based on the market clearing price. Some commenters maintain that if the Commission uses marginal costs, each generator should be paid the as-bid price for each unit, rather than the market clearing price based on the highest priced unit.⁴³ Grid Services suggests that using as-bid pricing possibly will lower energy prices, although it concedes that if suppliers accommodate their bids to an as-bid pricing regime, consumers will not see a benefit from the as-bid approach.

³⁹See Comments by Duke Energy, EPSA.

⁴⁰See Atlantic City Electric Company, 86 FERC ¶ 61,248, 61,904 (1999) (permitting new generators to be exempt from price caps).

⁴¹See Comments by California Commission, SDG&E.

⁴²See Comments by Cal. Mun. Utilities, SMUD.

⁴³See Comments by SMUD, Cal. Dep't of Water Resources, Grid Services.

The Commission finds that using marginal costs is the appropriate method for calculating bids during price mitigation. During a period when a supplier has available capacity, it should be willing to sell that capacity on a daily basis as long as it covers its marginal cost of producing it. Since marginal cost pricing best approximates competitive pricing, there is no need to include fixed or other costs in the bids.⁴⁴

In the auction context, the market clearing price best simulates a competitive market, since in a competitive market, producers receive the market clearing price, regardless of their individual costs. If suppliers know that they are going to receive only what they bid, they will attempt to bid the market clearing price, a practice known as "strategic bidding" and that introduces additional risks into the market. Also, as-bid pricing greatly complicates the settlement of forward contracts in real-time, as well as the pricing for congestion management and ancillary services.⁴⁵

When price mitigation is in effect, the Commission is using a combination of market clearing prices and as-bid prices for all non-proxy bids above the market clearing price. Generators will receive the market clearing price determined by the proxy bid, since that price best replicates the results that would be produced in a competitive market. In a competitive market, the marginal value of each unit sold is the same, so each seller should be entitled to receive the same price. In addition, the use of the market clearing price will permit generators with costs below the market clearing price to recover some amount for capital costs through scarcity rents. As discussed above, however, when a generator, which believes its marginal costs are above the proxy bid, submits a bid higher than the mitigated price calculated by the ISO, that generator will be paid on as-bid basis, subject to refund and justification.

Some commenters suggest that in addition to mitigated prices, the Commission should impose a high damage control price cap.⁴⁶ Since the price mitigation adopted here seeks to replicate competitive prices by requiring energy producers to bid at their marginal cost, the Commission sees no further reason to impose a high damage control cap. Imposing a price cap can, in fact, be counterproductive because it can discourage entry of new generation and discourage conservation. Additionally, because California needs to attract power from outside its borders, a California-only price cap would only serve to exacerbate possible scarcity for California.

⁴⁴See Alfred E. Kahn, *The Economics of Regulation: Principles and Institutions*, Volume 1 63-86 (John Wiley & Sons, Inc., New York, 1970).

⁴⁵See Alfred E. Kahn, Peter C. Cramton, Robert H. Porter, and Richard D. Tabors, *Pricing in the California Power Exchange Electricity Market: Should California Switch from Uniform Pricing to Pay-as-Bid Pricing?* A Study by the Blue Ribbon Panel Commissioned by the California Power Exchange, January 23, 2001.

⁴⁶See Comments by ISO, Cal. Dep't of Water Resources, CA Oversight Board.

The Western Power Trading Forum and Morgan Stanley contend that given the variation in marginal costs, such as the cost of fuel and air emissions credits, generators cannot provide a standing confidential price based on marginal costs. Mirant and Duke Energy maintain that daily gas prices need to be reflected. Mirant also is concerned that costs filed as part of Staff's price mitigation plan will be used improperly by the ISO to show that bid prices above these costs evidence market power. Mirant maintains that Staff's proposal does not properly reflect marginal cost and emphasizes that in competitive markets, prices may exceed marginal costs.

These comments are not directly applicable to the Commission's price mitigation plan. Under the Commission's plan, generators would not file a fixed price for price mitigation. They would file their heat and emission rate which would be used through a formula to calculate the mitigated bid. The Commission agrees with Mirant that these cost calculations may not be true marginal costs; they are merely a proxy price. Therefore, appropriate care should be taken in using this information in market analyses or other studies.

3. Calculation of Marginal Cost Prices

The comments raise a number of issues with respect to the calculation of marginal costs. Generators maintain that the Commission should include all variable costs and fixed costs, including opportunity costs, scarcity values, and marginal capacity value in computing marginal cost rates. Dynegy maintains that the Staff's proposal for using the costs of the marginal unit to set the rate for all generators will permit the efficient generators to recover costs, but will not permit the marginal generator to recover costs unless a factor for scarcity rent and opportunity cost is included. Dynegy proposes using a fixed cost figure of \$72/kw-year for a combustion turbine as a measure for scarcity and spark spreads to measure opportunity costs. EPSA argues that the proxy price approach used by the Commission in the March 9, 2001 refund order would be superior to calculating costs by individual unit. The Oversight Board maintains that while marginal cost is acceptable for most generators, a different measure needs to be implemented for true peaking units.

The use of marginal cost pricing generally reflects the prices that would be bid into an auction by generators in a competitive market. A competitive market, however, will not simply reimburse firms at their own marginal cost, since those firms with marginal costs below the market clearing price will receive scarcity rents to cover their fixed costs. In the proxy approach adopted here, marginal costs are approximated by using gas costs and emission credit information, which are effectively a unit's running costs. Using running costs as a proxy for marginal costs will still permit more efficient generators to receive scarcity rents, because they will receive the price of the least efficient unit dispatched. It also will not have significant impact on those firms with bilateral contracts for power, because only a portion of their power (that not previously sold) will be bid into the real-time market.

Some of the comments contend that the use of marginal cost pricing will not provide sufficient scarcity rents to the highest cost, most marginal generators, and contend that an adder should be

included to cover scarcity rents. However, the Commission sees no reason to include a scarcity adder. Because the Commission is requiring public utility load serving entities to submit demand bids indicating the prices at which their loads can be curtailed, the demand bids will provide an opportunity for all generators using proxy bids to receive scarcity rents.⁴⁷ Moreover, as pointed out above, the amount received through the real-time auction applies only to capacity available in the real-time market after their bilateral contracts are honored. Since bilateral contracts should be the principal means by which generators recover their total costs, generators should be willing to sell any residual real-time energy for any price at or higher than their marginal cost.

Generators also maintain that opportunity costs should be allowed as part of their bids. In most cases, opportunity cost should not figure into the calculation of bids, because power that is available in the real-time market has no real opportunity to be sold elsewhere. Therefore, the Commission will not permit suppliers to add a figure for opportunity costs.

4. Confidentiality of Cost and Bid Information

SoCal Edison, Northern California Power Agency, and CMUA maintain that the current requirement to keep bid and cost information confidential for six months should not be continued. They contend ratepayers need to know bid information contemporaneously so they can evaluate and protest the rates. CMUA maintains the contemporaneous disclosure of bid and cost information is required by section 205 of the FPA, which mandates the public disclosure of all rates and charges.

The Commission will not change the time period for keeping bid information confidential. The amount particular competitors bid is generally considered confidential business information. Disclosure of such information may lead to a reduction in competition because it will allow competitors to learn what their competitors are bidding and could lead to price collusion or coordination. Delaying disclosure of bid information is not in violation of the FPA. The FPA provides the Commission with discretion as to how to adapt its regulatory regime to changing conditions,⁴⁸ and therefore, in

⁴⁷In cases where the demand for energy exceeds the supply of energy at the marginal cost of the last unit dispatched, the market clearing price will rise to the level of the marginal buyer's reservation price (the amount they are willing to pay). This will efficiently allocate energy to those that value it the most (as shown by their willingness to pay). At the same time, it will provide scarcity rents to all generators using proxy bids.

⁴⁸See In re California Power Exchange Corp., 2001 U.S. App. Lexis 6153 (9th Cir. 2001) (Commission has authority to structure regulations to meet the requirements of market based rate regimes), Power Company of America v. FERC, 2001 U.S. App. Lexis 6728 (D.C. Cir. 2001) (regulations designed for traditional cost-based regulation need not apply to market-based regulatory regimes). See also Permian Basin Area Rate Cases, 390 U.S. 747, 776-77 (1968) (in the related

administering a regime of market-based rates, the Commission must recognize the need to keep bid information confidential in order to promote competition. In addition, section 205 of the FPA refers to the posting of rates and charges, not bids, and the actual charges for power are contemporaneously disclosed. With respect to the disclosure of individual generator's heat and emission rates, these rates are confidential business information that will not be disclosed.⁴⁹

E. Review and Duration of the Mitigation Plan

Generators support Staff's proposal to limit the mitigation to one year,⁵⁰ while others contend that mitigation must continue until the crisis has abated and the markets are competitive.⁵¹ The Commission concludes that the mitigation plan adopted here should be terminated no later than one year from implementation. During the period of a year, many aspects of the California market are likely to change, including the introduction of significant new generation. For example, Governor Davis' press release of April 4, 2001 cites to the California Energy Commission's current status report indicating that new generation totaling 4,168 MW will be on line by the end of August 2001 and there could be as much as 6,879 MW on line for the summer of 2002. In addition, within a year, the requirements of this order requiring greater demand response will be effective. Reliance on mitigation should not supplant or slow down efforts to add generation as well as develop more effective market mechanisms, and terminating this mitigation plan in a year will help ensure that all parties work to achieve these goals.

However, in order to evaluate the effectiveness of this plan, the Commission will institute a process for reviewing the plan and the conditions in the California market. On September 14, 2001, and quarterly thereafter, the ISO must file with the Commission a report analyzing how the mitigation plan is operating as well as the progress that has been made in developing new generation and demand response. Comments on the filing will be due 15 days from the filing of the ISO's report. The Commission will then decide whether any element of this plan warrants adjustment.

⁴⁸(...continued)

context of the Natural Gas Act, the Commission's broad responsibilities demand a generous construction of its statutory authority).

⁴⁹See 18 C.F.R. §§ 388.112 (2000), 385.206 (e), 385.213 (c)(5), 385.410 (c) (providing for confidential treatment for business sensitive information).

⁵⁰See Comments by EPSA, Dynegy, Duke Energy, Reliant.

⁵¹See Comments by Southern California Water Co., City of San Diego, Cal. Municipal Utilities Assoc., California Commission, CA Oversight Board, City of San Diego.

F. ISO's Market Stabilization Plan

The ISO filed a detailed statement of a market stabilization plan that it is contemplating filing with the Commission. In this order, the elements of that plan dealing with price mitigation have been considered as further comments on the staff plan and the Commission has resolved how mitigation will be accomplished. Other elements of this plan, such as the day-ahead and hour ahead market proposal, go beyond the scope of this proceeding and would need to be filed under section 205, so that these proposals can be reviewed appropriately by all parties. The ISO should not go forward with any plans, such as the purchase of computer equipment or software, to implement these proposals until the Commission has reviewed and accepted its filing.⁵²

III. Proposal for an Escrow Account for Past Unpaid Bills

The Commission is requesting comment within 30 days on whether the ISO should be required to institute, on a prospective basis, a surcharge on power sales that will be maintained in an escrow account in order to cover the three California Investor Owned Utilities (IOU) generators' past unpaid bills to suppliers. The surcharge would be applied only on real-time power sales through the ISO to the three IOUs.⁵³ Comments should address whether such a surcharge would help to increase production by creating a greater assurance that generators will be paid. They also should address whether the surcharge should be limited only to transactions for the three IOUs or should be spread over all purchasers, and whether the surcharge and escrow account should cover all past due amounts or only future unpaid bills starting from the date the plan is begun. In addition, comments should address how should a plan would affect current bankruptcy proceedings.

IV. West-Wide 206 Investigation

Under section 206 of the FPA, the Commission is instituting an investigation into the rates, terms and conditions of public utility sales for resale of electric energy in interstate commerce in the WSCC other than sales through the California ISO markets, to the extent that such sales for resale involve: (1) electric energy sold in real-time spot markets (i.e., up to 24 hours in advance); and (2) take place during conditions when contingency reserves (as defined by the WSCC) for any control area fall

⁵²See *GridFlorida LLC*, 94 FERC ¶ 61,363, at 61,325 (2001) (software should not be acquired until approval is given).

⁵³See *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1301-02 (D.C. Cir. 1992) (cost spreading permitted to solve "extraordinary take-or-pay problem"); *Elizabethtown Gas Co. v. FERC*, 10 F.3d 866, 873-74 (D.C. Cir. 1993) (volumetric surcharge permitted to recover above market costs of abandoned coal gasification project); *United Gas Distribution Co. v. FERC*, 88 F.3d 1105, 1184-86 (D.C. Cir. 1996) (departure from traditional cost causation principles permitted to recover restructuring costs).

below 7 percent. The Commission believes that currently rates, terms and conditions of service for such sales may not, under current market rules and under certain conditions, be just and reasonable and should be modified.

The Commission proposes that all non-hydroelectric generators and marketers in the WSCC with energy operationally and contractually available in real-time (public utilities and non-public utilities)⁵⁴ would be required to offer that real-time energy for sale at that time. The generators would not be required to sell that energy into California; they would only have to offer the power for sale in any location. Any sales made in other real-time spot markets in the WSCC would also be subject to price mitigation and we seek comment on what this price mitigation should be. The WSCC price mitigation would be limited to system conditions when contingency reserves (as defined by the WSCC) for any control area fall below 7%.

In addition, the market-based rate authority of public utility sellers selling in the WSCC region would be conditioned to ensure that they do not engage in the type of anticompetitive behavior discussed elsewhere in this order.

We will establish a refund effective date 60 days from the date on which notice of our initiation of the investigation is published in the Federal Register.

The changes proposed herein for the WSCC are intended, to the extent possible, to mirror those being applied in Docket Nos. EL00-95-012, et al., as discussed above.

Comments should be submitted within 10 days.

The Commission orders:

(A) The ISO shall submit tariff changes to comply with this order within 15 days of the date of this order.

(B) Generators covered by this order are required to file their heat rates and emission rates, subject to confidential treatment, with the Commission and the ISO within 5 days of this order.

⁵⁴We propose to impose this condition on non-public utilities as a condition of using the interstate transmission facilities of public utilities. Since transmission constraints are contributing to the problems in the WSCC, non-public utility generators should not be able to avail themselves of the use of the public utility-controlled transmission facilities while not committing themselves to help solve the problems that have arisen.

(C) The market-based rate authority of public utility sellers into the California market is subject to the conditions discussed in the order.

(E) By June 1, 2001, the ISO and public utility load serving entities must submit tariff changes providing for demand responsive bids as described in the order.

(F) On September 14, 2001, and every three months thereafter, the ISO must submit the report on conditions in the California market as described in the order.

(G) This mitigation plan will become effective May 29, 2001.

(H) The \$150/MWh breakpoint and refund approach as discussed in the body of the order shall remain in effect through May 28, 2001.

(I) This mitigation plan is conditioned on the California ISO and the three investor owned utilities (IOUs) filing an RTO proposal by June 1, 2001.

(J) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by section 402(a) of the department of Energy Organization Act and by the Federal Power Act, particularly section 206 thereof, and pursuant to the Commission's Rules of Practice and Procedure and the regulations under the Federal Power Act (18 C.F.R. Chapter I), a public hearing shall be held in this proceeding concerning the justness and reasonableness of the rates, terms and conditions of public utility sales for resale of electric energy in interstate commerce in the WSCC other than sales through the California ISO market, as discussed in the body of this order.

(K) The parties may submit comments to the Commission, as described in the body of this order, within 10 days of the date of this order.

(L) The Secretary shall promptly publish in the Federal Register a notice of the Commission's initiation of the proceeding under section 206 of the FPA in Docket No. EL01-68-000.

(M) The refund effective date established pursuant to section 206(b) of the FPA shall be 60 days following publication in the Federal Register of the notice discussed in Ordering Paragraph (L) above.

By the Commission. Commissioner Massey dissented in part with a separate statement attached.

(S E A L)

David P. Boergers,
Secretary.

APPENDIX A

Comments Filed On Staff Proposal

Arizona Residential Utility Consumer Office (RUCO)

Automated Power Exchange, Inc. (APX)

California Department of Water Resources (DWR)

California Electricity Oversight Board

California Independent System Operator Market Surveillance Committee (ISO MSC)

California Independent System Operator Corporation (ISO)

California Municipal Utilities Association (CMUA)

City of San Diego (San Diego)

County of San Diego (County)

Duke Energy North America LLC and Duke Energy Trading and Marketing (Duke Energy)

Dynegy Power Marketing, Inc., El Segundo Power LLC, Long Beach Generation LLC, Cabrillo Power I LLC and Cabrillo Power II LLC (Dynegy)

Electric Power Supply Association (EPSA)

Enron Power Marketing, Inc. (Enron)

Grid Services, Inc. (Grid Services)

Independent Energy Producers Association (IEP)

Metropolitan Water District of Southern California (Metropolitan)

Mirant California, LLC, Mirant Delta, LLC, and Mirant Potrero, LLC (collectively Mirant)

Morgan Stanley Capital Group, Inc.

Northern California Power Agency (NCPA)

PG&E Corporation (PG&E)

Public Utilities Commission of the State of California (California Commission)

Reliant Energy Power Generation, Inc. (Reliant)

Sacramento Municipal Utility District (SMUD)

San Diego Gas & Electric Company (SDG&E)

Southern California Edison Company (SoCal Edison)

Southern California Water Company

Western Power Trading Forum (WPTF)

Williams Energy Marketing & Trading Company (Williams)

Dr. Jian-zhong Zhong

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.

Investigation of Practices of the California
Independent System Operator and the
California Power Exchange

Docket No. EL00-98-000

California Independent System Operator
Corporation

Docket No. RT01-85-000

Investigation of Wholesale Rates of Public Utility
Sellers of Energy and Ancillary Services in the
Western System Coordinating Council

Docket No. EL01-68-000

(Issued April 26, 2001)

MASSEY, Commissioner, dissenting in part:

Today's order represents the Commission's final opportunity to put in place adequate measures to protect consumers in California and other parts of the western market from runaway prices this summer. There are many good features to the order that could prove helpful this summer and beyond. But the order is overly restrictive in some critical respects and consequently will fail to achieve our objectives. Because of these restrictions, I must dissent in part from the order.

We are now eleven months into the California calamity. It has had a breathtaking and staggering effect on the western economy, and there is no end in sight. Now is not the time for half-a-loaf solutions. My vote cannot be compromised so cheaply. I

compromised to vote for the December 15 remedies order even though it did not contain the effective price relief I championed, or anything close to it, and I now regret that vote.¹ It is now over four months and many billion dollars later. Our refund orders have been paltry and, in my opinion, arbitrary. Prices are not just and reasonable now and will not be this summer, and the economic carnage is spreading throughout the western interconnection. For example, four hundred and six workers were put out of work when Georgia Pacific shut a production facility in Washington state because of skyrocketing electricity bills. The Seattle-Tacoma Airport estimates that this year, its electric bill will triple to \$50 million, skyrocketing to 25% of its operating budget. Countless other examples of economic harm throughout the western interconnection could be cited. The point is that now is the time for effective problem solving, and this order, though it has some salutary features, falls short.

This order establishes a monitoring and mitigation program that will replace the \$150 benchmark approach adopted in our December 15 order. Some of the positive features of today's order are: enhancing the California ISO's ability to coordinate and control planned outages; requiring sellers (both public utilities and others using the ISO's grid) to offer all available power to the ISO real time market during all hours; requiring public utility load serving entities to submit demand bids to the ISO's real time market during all hours; establishing conditions on sellers' market based rates to prevent anticompetitive bidding behavior in the real time market during all hours; and requiring the ISO to submit weekly reports on outages and bidding behavior for all hours. These are solid measures that could prove helpful this summer and beyond.

There are, however, four aspects of the order to which I must dissent.

First, the price mitigation feature is too restrictive because it is applied only when an operating reserve emergency is called. The price mitigation, which limits generators to a cost-based bid into the real time market, should apply during all hours in California. Such an approach would not be the least bit punitive. It would, in fact, replicate the manner in which the single price auction is supposed to work, that is, the single price auction theoretically provides a powerful incentive for generators to bid their running costs into the market. That is the most effective generator strategy for ensuring dispatch, or so the theory goes.

The problem is that it has not worked that way in the California market. Economic withholding, which is bidding up the price well above costs just because you can, is a

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pervasive problem, and as a result, high prices that exceed a just and reasonable level are a severe problem in the California market. The record is devoid of any evidence that the problem is limited to hours when an operating reserve margin alert at stages 1, 2, or 3 is in effect. The evidence is persuasive that the problem exists twenty four hours a day, seven days a week. I found the California ISO study

¹San Diego Gas & Electric Company, et al., 93 FERC ¶ 61,294 (2000), reh'g pending.

by Anjali Sheffrin, the ISO's director of market analysis, to be compelling.² Dr. Sheffrin concluded that economic withholding is a severe problem in all hours, not simply capacity constrained hours, and I agree. Her analysis concludes that from May to November 2000, withholding that lead to inflated market prices in the ISO's real time market occurred in over 98% of hours. According to my calculations, the ISO declared a stage one or higher alert in only 5% of the hours during this period. For Dr. Sheffrin's study period, the price mitigation proposed in this order would have missed 93% of the hours when market power drove up prices.

The solution is to require generators to bid their costs in all hours. This replicates the intent of the single price auction concept. What's more, the more efficient generators would still make money under such an approach, perhaps a lot of money, because the market clearing price that all generators get would be set by the highest cost generator, probably an inefficient older gas fired generator with a high heat rate.

Because the price mitigation feature applies only during operating reserve alerts, and not during other periods, I have no confidence that prices will be just and reasonable during all hours. This agency is statutorily required to ensure just and reasonable prices at all times, and this standard in federal law is not limited to stage alert hours.

Today's order also narrows the existing refund condition adopted in the December 15 order. I am not confident I can adequately explain the refund condition that will remain in place for the California market, but I know that it has been substantially narrowed by this order. I object to that as well.

Second, the duration of the monitoring and mitigation features of this order is too restrictive. Today's order would expire one year from now unless expressly modified by the Commission. This period of time is too short. I would allow the monitoring and mitigation features to remain in place for at least eighteen months.

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Third, I object to the RTO filing conditions. Under the order, if the California ISO and the three California investor-owned utilities fail to make an RTO filing by June 1, the entire order turns into a pumpkin and is of no effect. As I read it, this order becomes null and void. This makes no sense. It seems to stand for the proposition that this agency will make no effort to ensure just and reasonable prices if the California ISO and all three of the California IOUs fail to make an RTO proposal. I cannot support such a condition. The California ISO and the three utilities must make an RTO filing, but this has no relevance to price mitigation over the next year.

²See Comments of the California Independent System Operator on Staff's Recommendation on Prospective Market Monitoring and Mitigation, Attachment C: Empirical Evidence of Strategic Bidding in California ISO Real Time Market (March 21, 2001).

And fourth, the scope of the section 206 investigation that is ordered should be broader. I concurred to our December 15 order, and advocated that the Commission initiate a section 206 investigation into jurisdictional wholesale sales for the entire western interconnection, setting a refund effective date 60 days hence. As a legal matter, such an investigation is a necessary predicate to any possible price relief outside of California's spot markets.

This order opens an extraordinarily narrow 206 investigation for the western interconnection, and I commend my colleagues for at least going this far, but the approach is much too narrow to hold any promise of effective price relief. I had advocated an investigation, and refund condition, for all transactions of one month or less. The investigation and refund condition set out in this order only apply, however, to transactions of 24 hours or less that occur during a reserve deficiency of 7% or less. I fear that the investigation and refund condition are so narrowly circumscribed that they do not hold the potential for meaningful price relief. It is my understanding that many of the transactions that are driving the high prices in Washington, Oregon and other western states are for terms well exceeding 24 hours. This type of transaction would not be subject to this investigation nor to price relief. I object to this omission.

Finally, let me underscore my great concern about the high price of natural gas delivered into California markets. The transportation differential into California often exceeds ten dollars, and is often substantially more at various intrastate delivery points. The transportation differential into other large markets such as New York and Chicago is usually less than a dollar, and sometimes no more than a few cents. The high cost of natural gas delivered into California is then used to justify high wholesale electricity bids into the ISO market. An inefficient, high heat rate, generator using a considerable amount of high priced natural gas then sets the market clearing price that all sellers are paid. Thus, the high transportation differentials into California gas markets have a particularly pernicious effect when coupled with a single price auction for electricity.

I urge this agency to take all available action to mitigate these high transportation differentials. We must actively explore any jurisdiction we may legitimately have that affects the so-called gray market. We must take a second look at whether lifting the price

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cap for secondary market pipeline capacity was in the public interest. We must vigorously investigate any allegations of withholding or market manipulation or affiliate abuse. We must certificate new interstate capacity that is needed for the markets to function efficiently, and, as Commissioner Breathitt has pointed out on more than one occasion, we must work with the state of California to ensure that there is adequate take away capacity in the intrastate market. I am open to any and all ideas, but my attention was riveted on this issue by our recent staff order setting the so-called proxy price for electricity for the month of February. The proxy clearing price was \$430 per Mwh, and roughly \$350 of that amount was the price of natural gas for an inefficient generator. I concluded that electricity prices in California would remain very high if based upon a very high price for natural gas. This issue has not gotten nearly the attention it needs, and I highlight it to urge more forceful Commission action in this area.

Today's order is only the latest in a series of actions the Commission has taken with respect to the problems facing the California and western markets. Despite the hard work of our excellent staff on these matters, the actions of this agency, though well intentioned, have fallen short of ensuring just and reasonable prices. True, we cannot solve all of the west's energy problems. A large share of the responsibility falls on state and local government entities. We can, however, insist that wholesale prices are just and reasonable in all hours. Indeed, we must do so. Under federal law, that is solely our responsibility and no one else's.

We face the second summer of out of control electricity prices out west. This may be our last chance. We should seize it fully. Because we fail to do so in today's order, I must dissent in part.

William L. Massey
Commissioner