UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Curt Hébert, Jr., Chairman;
William L. Massey, Linda Breathitt,
Pat Wood III, and Nora Mead Brownell.

San Diego Gas & Electric Company, Complainant, v. Sellers of Energy and Ancillary Service Into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange, Respondents.	Docket No. EL00-95-031
Investigation of Practices of the California Independent System Operator and the California Power Exchange	Docket Nos. EL00-98-030 EL00-98-033
California Independent System Operator Corporation	Docket Nos. RT01-85-000 RT01-85-001
Investigation of Wholesale Rates of Public Utility Sellers of Energy and Ancillary Services in the Western Systems Coordinating Council	Docket Nos. EL01-68-000 EL01-68-001

ORDER ON REHEARING OF MONITORING AND MITIGATION PLAN
FOR THE CALIFORNIA WHOLESALE ELECTRIC MARKETS,
ESTABLISHING WEST-WIDE MITIGATION, AND
ESTABLISHING SETTLEMENT CONFERENCE

(Issued June 19, 2001)

Introduction and Summary

On April 26, 2001, the Commission issued an order (April 26 Order) [1] establishing new price mitigation for sales in the California Independent System Operator's (ISO) ancillary services and imbalance energy markets (spot markets). [2] The April 26 Order also instituted an investigation under section 206 of the Federal Power Act (FPA) into the reasonableness of the rates for wholesale sales in the spot markets [3] in the Western Systems Coordinating Council (WSCC). [4] In so doing, we were mindful that the West is a single market which is at once inextricably interrelated, yet characterized by important differences. Fundamental in this regard is that the California spot markets are presently administered largely through the ISO's centralized clearinghouse, which operates a single price auction, while sales in the rest of the West are consummated on an individual bilateral contract basis and not through a centralized clearinghouse.

We have received and carefully considered many comments on how to change or improve our price mitigation in California and on whether and how to initiate price mitigation in the rest of the WSCC. Today, we will prescribe price mitigation for spot markets throughout the West which will guide the WSCC's energy markets through the difficult process of self-correction. In so doing, we seek to intervene in markets in as limited a manner as possible consistent with our responsibilities to ensure just and reasonable rates under the FPA, to rely on market principles wherever we can, and to balance carefully the need for price relief against the need for price signals to attract critical supply entry.

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[1] San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, 95 FERC ¶ 61,115 (2001). On May 25, 2001, the Commission issued an order providing clarification and preliminary guidance on the implementation of the mitigation plan. 95 FERC ¶ 61,275 (2001).

[2] The price mitigation established in the April 26 Order replaced the price mitigation previously in effect for such sales, and is an outgrowth of a Commission investigation under section 206 of the Federal Power Act (FPA) of the reasonableness of rates for public utility sales through the markets operated by the ISO and the California Power Exchange (PX).

[3] As used throughout this document, the terms "spot markets" or "spot market sales" means sales that are 24 hours or less and that are entered into the day of or day prior to delivery.

[4] References throughout this document to the WSCC are intended to refer only to the United States portion of the WSCC.

Today's order is one of a series of mitigation directives that began with our underlying order, issued December 15, 2000, [5] to correct dysfunctions in the wholesale power markets operated by the ISO and PX. Specifically, the elimination of the mandatory buy-sell requirement and the elimination of the PX rate schedule have helped to turn the tide in eliminating California investor-owned utilities' chronic reliance on spot markets. The effects of the price mitigation directed by our December 15 Order and the actions of the State of California in moving to longer-term contracts and conservation efforts have had a significant dampening effect on prices. As a result, California investor-owned utilities no longer rely on spot markets for meeting the entirety of the needs of the electric customers they serve. California now forecasts that it will only rely on the spot markets this summer for about 20% of its on-peak energy requirements, as compared to 100% prior to the December 15 Order. [6] In fact, in certain hours, the ISO data show no purchases whatsoever in its imbalance energy market. Because this market is the closest in time to when load must be met, it can exhibit the highest prices in times of shortage.

The reduction of the size of the ISO's spot market to levels more reflective of appropriate risk management was, and remains, the cornerstone of our price mitigation. The reduction of the size of California's spot market in conjunction with the mitigation plan adopted in our April 26 Order, as well as a dramatic reduction in gas prices and fewer generation outages in California, are among the factors that have had the effect of lowering energy prices in the West. Western power prices have fallen recently, with reports by the ISO citing peak daytime purchase costs of less than $100/MWh and off-peak power purchases of less than $20/MWh. During the week ending June 9, prices for last-minute peak power at Western trading hubs fell to less than $55/MWh from a high of about $170/MWh earlier in the week.[7] This trend continued into the week ending June 16 with prices hovering between $50/MWh and $65/MWh at most of the Western power indexes.[8] In addition, prices for Western forward contracts are also down dramatically, with year

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[5]San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, 93 FERC ¶ 61,294 (2000) (December 15 Order).

[6]Update of California Department of Water Resources Power Purchase Contract Efforts, California Department of Water Resources (May 31, 2001).

[7]Platts Power Markets Week, June 11, 2001. Prices of Spot Electricity, Week Ending June 9 - Daily On-Peak Indexes for Calif-Ore Border, Mid-Columbia, Palo Verde, Four Corners, North Path 15, and South Path 15 (Six Western Indexes).

[8]Megawatt Daily's Market Report, June 11 through June 14, 2001, for Six Western Indexes.

2002 forward transactions dropping from $127 to $68/MWh, and 2003 forward contracts from $60 to $41 in the past month. [9]

While progress has been made in correcting market dysfunctions, the dysfunctions will not be fully corrected until additional load is moved from the spot market to longer-term contracts (a mixed portfolio of supply contracts) and the basic structural defect of inadequate supply in the West is corrected. The Commission therefore has determined that in order to ensure that rates for sales for resale in spot markets in California and the rest of the WSCC continue to fall within a zone of reasonableness, we will provide for price mitigation in California and throughout the remainder of the WSCC during reserve deficiency hours, i.e., when reserves in California fall below 7 percent (in California, Stage 1 is called when reserves fall below this level). [10] As we found in our April 26 Order, this is when the level of demand approaches the amount of available supply and suppliers have the greatest opportunity to exercise market power. In addition, based on the comments received and based on prices that we recently have observed in California in hours where there is no reserve deficiency, we conclude that as an added measure in protecting customers, at this time it is also appropriate to provide for a type of price mitigation for spot market sales during other hours.

As noted, we find it appropriate to provide for price mitigation in the spot markets in California and throughout the West in reserve deficiency hours, i.e., when reserves fall below 7 percent in California. As we found in our April 26 Order, at these times supply is scarce relative to demand and sellers have the greatest ability to dictate price. The price mitigation we will adopt for these hours will be based on market principles and will apply to California and the remainder of the West. Because there is no centralized clearinghouse for spot market sales in the WSCC other than in the ISO, and therefore no ability to develop a separate market clearing price for sales outside the ISO, we will apply the ISO market clearing price as the maximum price to all sales in the WSCC spot markets during reserve deficiency hours (Stage 1 or above) called by the ISO. We expect prices to be below this level to reflect the degree to which supply exceeds demand. Thus, our mitigation will apply to all sellers in the WSCC, including marketers and non-public utilities. It is critical to treat all sellers alike to remove the incentive to sell in one area versus another when a reserve deficiency is called by the ISO. We also will allow sellers other than marketers the opportunity to justify prices above the market clearing price during reserve deficiency hours and we will provide guidance on the specific showing that a seller must make.

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[9] Platt's Power Markets Week, June 11, 2001, pp. 1, 16. As used throughout this document, "forward contracts" or "forward transactions" means any transactions with a future delivery that are entered into more than 24 hours before commencement of service.

[10] Our April 26 Order referred to Stage 1 being called by the ISO when reserves in California fall below 7.5%. The correct number is 7%.

In non-reserve deficiency hours, when supply is not scarce, prices should be disciplined sufficiently and should reflect an accurate measure of the shortage confronting the West and provide a clear price signal to induce new supply. However, commenters are concerned that prices may remain high in hours when reserves are adequate. There is little doubt that regulators are ill-equipped to replicate the premiums which a functioning market assigns to a diminishing supply. It is precisely for this reason that, in our April 26 Order, we did not attempt to develop an administratively determined component for shortage and chose instead to rely on prices in non-reserve deficiency hours to send the correct price signal. Nevertheless, at this time, we will implement price mitigation in non-reserve deficiency hours as well. However, we will use a modified form of our present mitigation during non-reserve deficiency hours -- to ensure that prices will continue to induce new supply. We do so as a discretionary matter to provide an added measure to protect customers and the economies of the Western states, even though we view prices above the marginal cost of generation in these hours as a necessary reflection of the supply shortage at hand. Instituting mitigation in these hours will protect customers so that all energies and attention can be harnessed on the tasks of adding new supply and upgrading energy infrastructure and of completing California's transformation from 100% reliance on the spot market to a balanced portfolio of short, medium and long-term supply arrangements, as well as protecting neighboring states from undue harm. Later in this order, we direct the State of California and parties in the San Diego Gas & Electric Company complaint proceeding to settlement proceedings to complete the task of settling past accounts and structuring the new arrangements for California's energy future. We will monitor our price mitigation in non-reserve deficiency hours to ensure that it is providing the incentives needed to correct the present market dysfunctions. We will adjust the mitigation, as needed, to induce long-term supply entry and the forward contracts required to support that entry.

The price mitigation we are adopting again relies on market solutions and mechanisms to the maximum extent possible. We will continue to use a single market clearing price derived from must offer and marginal cost bidding requirements for hours of reserve deficiency in California's organized spot market. We also will adapt these market clearing prices for use in all other hours, both in California's spot markets and the West's spot markets. Before describing in general the price mitigation that will be required in the ISO's markets and in the bilateral spot markets in California as well as the rest of the West, we believe it is important to enumerate the major considerations we have balanced in developing appropriate price mitigation.

- There is a critical interdependence among the prices in the ISO's organized spot markets, the prices in the bilateral spot markets in California and the rest of the West, and the prices in forward markets.

- Uniform price mitigation for California and the balance of the West should reflect the same essential competitive market principles, while recognizing the significant differences in the structure of those markets. It also should eliminate incentives for so-called "megawatt laundering". [11]

- In exercising our statutory responsibility to ensure just and reasonable rates, i.e., rates that fall within a zone of reasonableness, we must balance the need for immediate price relief for customers against the need for price signals to attract new supply and demand-side investments.

- As mentioned in our prior orders, the cornerstone of remedying the dysfunctions in the energy markets in the West and in bringing both spot and forward prices down over the last few months is eliminating California's excessive reliance on spot markets. While significant progress has been made, some 20 percent of California's load remains in the ISO's spot markets at peak periods. [12]

- Buyers and sellers need certainty and closure. To the extent possible, our price mitigation should have clear rules, should set prices before they are charged and should not subject prices to change or adjustment after financial settlement of the day's transactions. Similarly, it should not rely on costly and time consuming administrative processes to set, adjust or justify prices.

- Abuse of market power cannot and will not be tolerated. Sellers will be subject to losing their market based rates for engaging in anticompetitive conduct. Further, as a condition of continued authorization of market-based rates, public utility sellers in the WSCC must agree to refunds, with interest pursuant to 18 C.F.R. § 35.19a, of any overcharges resulting from anticompetitive bidding or behavior.

To satisfy these principles, the mitigation plan will consist of the following measures:

- We will retain the use of a single market clearing price with must offer and marginal cost bidding requirements for sales in the ISO's spot markets in reserve deficiency hours, i.e., Stage 1 when reserves are below 7 percent in California. Sellers in the ISO's single price auctions will receive the hourly market clearing price. For sales outside the ISO's single price auctions (bilateral sales in California and the rest of the WSCC) we will apply this clearing price as a maximum price. Sellers outside the ISO's single price auction will receive the prices they negotiate up to this maximum price. There are, however, three adjustments to the clearing price methodology we have previously used.

First, marketers will be required to bid as price takers. This means that marketers cannot bid higher than the market clearing price.

[11] The term "megawatt laundering" describes behavior where a supplier schedules supply out of state and then re-imports that power to avoid a mitigated price.

[12] Recent data indicates that the reliance on the spot market is higher during off-peak periods.

Second, we will require sellers that own generation to submit bids during reserve deficiencies that are no higher than the marginal cost to replace gas used for generation (i.e., what the seller would pay to procure gas at the last minute) plus variable O&M costs.

Third, we instruct bidders to invoice the ISO directly for the cost to comply with emissions requirements and for start-up fuel costs and direct the ISO to file a rate mechanism to bill those costs over the entire load on the ISO system. These cost inputs have proven too varied to standardize in a single market clearing price.

Sellers other than marketers will be allowed the opportunity to justify bids or prices above the maximum prices and we will provide guidance later in this order on what sellers that seek to do so must demonstrate.

- For spot market sales, both in the WSCC and in California, in all non- reserve deficiency hours (i.e., when reserve levels in the ISO exceed 7%), we will adapt the use of these market clearing prices. Eighty-five percent (85%) of the highest ISO hourly market clearing price established during the hours when the last Stage 1 (not Stage 2 or 3) was in effect will, absent justification, serve as the maximum price for the subsequent period. For example, if the highest hourly market clearing price during a Stage 1 is $140/MWh, spot prices in all subsequent non-reserve deficiency hours beginning when Stage 1 is lifted can be no higher than $119/MWh (i.e. 85 percent of $140/MWh). Sellers through the ISO's single price auction will receive the hourly market clearing price, but that clearing price will not exceed $119/MWh.[13] For example, if the market clears at $90/MWh all bidders in the ISO's auctions will receive $90/MWh for that hour. However, bids are limited to $119/MWh and, therefore, the clearing price during the period will never exceed $119/MWh. For sales outside the ISO's single price auctions (bilateral sales in California and the rest of the WSCC), sellers will receive the prices they negotiate up to the maximum price, in this example, up to $119/MWh. This maximum clearing price will remain in place until the next Stage 1 is declared and a new price is set. When that Stage 1 is lifted, 85% of the highest hourly market clearing price from that period will carry forward as the new maximum price. Sellers other than marketers will be allowed the opportunity to justify bids or prices above the maximum prices and we will later in this order provide guidance on what sellers that seek to do so must demonstrate.

- The mitigation plan will become effective beginning on the day following the date this order is issued.[14]

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[13] As we explain later, the ISO is required to add 10 percent to the market clearing price paid to generators for all prospective sales in its markets to reflect credit uncertainty. This adder will not be reflected in the market price for the rest of the WSCC.

[14] We will grant waiver of notice for the ISO's approved rate mechanism to recover the cost of

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- We will continue to apply all price mitigation to non-public utilities as a condition of selling into the spot markets which are the subject of this order and as a condition of using the interstate transmission grid under our jurisdiction.

- We will reaffirm that all public and non-public utilities who own or control generation in California must offer power in the ISO's spot markets. This requirement applies to any non-hydroelectric resource whether owned or under contract to the extent its output is not scheduled (or committed for minimum operating reserves) for delivery in the hour. We will also require all public and non-public utilities in the remainder of the WSCC to offer in the spot market of their choosing any non-hydroelectric resource whether owned or under contract to the extent its output is also not scheduled (or committed for minimum operating reserves) for delivery in the hour.

- The price mitigation will terminate on September 30, 2002.

- We will establish settlement proceedings at this Commission to address any and all issues to ensure that California completes the transformation of its load to long-term contracts. The Parties in the San Diego Gas & Electric Company complaint proceeding and the State of California are directed to participate in good faith in these proceedings.

We emphasize that the rate mitigation prescribed in this order is part of a series of steps the Commission has taken to remedy dysfunctions in California wholesale power markets. However, as we recognized in our first remedial order on December 15, 2000, many of the critical remedies that need to be taken fall either wholly or in part within the jurisdiction of the State of California. In particular, the consummation of additional long-term wholesale contracts, the development of demand side response signals, the siting of new generation and transmission, and the construction of intrastate natural gas delivery infrastructure are critical to remedying the current market dysfunctions and are dependent on State action. We recognize the significant progress that California has made thus far and urge further implementation of these critical measures. We stand ready to assist in these efforts to the extent possible within our authority.

Finally, in taking action in today's order as well as in prior orders in these dockets, beginning on December 15, 2000, the Commission has taken careful, reasoned steps to fulfill its statutory responsibilities under the FPA. The Commission's statutory responsibility to set just and reasonable

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[14](...continued)
emission requirements to be effective on the day following the date this order is issued. Absent a new reserve deficiency on the ISO's system declared before the effective date of the price mitigation outlined in this order, the market clearing price carried forward for non-reserve deficiency hours is $108.49/MWh (i.e. 85 percent of $127.64/MWh) (May 31, 2001, clock hour ending 1400).

rates gives it broad authority to adapt its ratemaking policies to the practical realities facing it. The Supreme Court ruled very early on that individual company cost-of-service rates were not the sine qua non of rate regulation, and that no single method of ratemaking is sacrosanct as the only means to reach the statutory goals. Rather, the value of any ratemaking policy is to be judged by its ability to meet the statutory goal of assuring that rates remain within a zone of reasonableness consistent with the maintenance of adequate service.

The ratemaking power granted the Commission under the FPA includes the authority to set the rules, regulations, practices, and contracts affecting rates, as well as the rates themselves. The Commission's orders related to the California markets have sought to establish a structure within which market forces will operate to achieve the statutory goal. In this order, the Commission continues the efforts of its earlier orders to modify the existing market structure throughout the West to minimize the potential for market power abuse, and thus to protect against possible unjust and unreasonable rates, while, at the same time, maximizing the incentive for increased supply in the entire western region.

I. Background

In an order issued August 23, 2000, [15] 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 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 a variety of remedies for the California wholesale electric markets, which included, in part, elimination of the mandatory PX Buy-Sell requirement, establishment of penalties for underscheduling load, a requirement for an independent governing board for the ISO, and a requirement for the filing of generation interconnection procedures.

As an interim measure, the Commission also 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

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

having to pay refunds for prices charged above the breakpoint. [16] 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. [17] Comments and reply comments on how to replace the interim break-point were filed with the Commission. In March 2001, Commission Staff issued a recommendation for prospective market monitoring and mitigation for the real-time electric market, and comments were filed on this proposal. The comments focused in particular on the method used for price mitigation and the periods when mitigation would be applied.

On April 26, 2001, the Commission issued its order adopting a prospective monitoring and mitigation plan for real-time California wholesale electric markets. The Commission's plan included the following elements:

It enhanced the ISO's ability to coordinate and control planned outages during all hours.

It required sellers with Participating Generator Agreements (PGAs), as well as non-public utility generators located in California that voluntarily make sales through the ISO's markets or 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.

It required 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.

It established 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.

It required 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.

It established 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, beginning at a Stage 1 alert, which is defined as having reserves of 7 percent or less. Under this mechanism, the

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[16] On 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.

[17] 93 FERC ¶ 61,294 at 61,983, 61,996-97.

Commission established a formula (based on gas-fired generation) that the ISO can use to establish the real-time market clearing price when mitigation applies. Higher bids were permitted if they could be justified.

In the April 26 Order, the Commission also established an inquiry into whether a price mitigation plan similar to the one for California should be implemented in the WSCC. The order invited comment on how such a plan should be structured.

The parties listed on Appendix A have filed for rehearing of the April 26 Order. A number of parties have filed motions for late intervention. While the Commission ordinarily does not permit late interventions after an order has been issued solely to file for rehearing, the Commission will grant the late interventions in this instance because of extensive overlap of the issues between the California-oriented parts of the April 26 Order and the West-wide investigation instituted in that order, and the fact that the April 26 Order authorized additional comments and interventions for purposes of the latter. Appendix B lists those filing comments in the section 206 proceeding with respect to the WSCC.

II. Discussion

As described earlier, the Commission is adopting a mitigation plan covering both California and the remainder of the WSCC during all hours for spot market sales. In the following sections, the Commission will address the rehearing requests and the West-Wide comments relating to this mitigation plan.

A. Outage Coordination

The April 26 Order found that in order to maintain sufficient generation capacity to meet market needs, the ISO must work with California generators to coordinate generating unit maintenance and outages, so that sufficient energy will be available when needed while also providing for reliable plant operation. The order required the ISO to make a tariff filing proposing a mechanism for outage coordination. The ISO made its compliance filing on May 11, 2001.

Most parties are in favor of such outage coordination. The CPUC, however, states that procedures relating to outage control and coordination are within the state's jurisdiction. CAC/EPUC contends that outage coordination may unreasonably burden QF facilities, because their outages are affected by their thermal host. DWR contends the outage controls should not be applied to hydroelectric generators. Duke, on the other hand, protests the ISO's proposal and asks the Commission to clarify the need for truly cooperative standards and procedures.

The ISO has the authority to coordinate and control generation outage schedules for resources under PGAs. The Commission clarifies that only the ISO's outage coordination role will be extended to all other in-state generating facilities insofar as these generators must submit to the ISO maintenance schedules for their generating units. This will provide the ISO with the information necessary to maximize the efficient use of all in-state resources. For example, with this information, the ISO will be able to determine whether to schedule generation under its control based on when other generation resources will be out-of-service. The ISO, however, will not be authorized to schedule maintenance for units not under a PGA.

B. Selling Obligations

The mitigation plan requires those generators with PGAs, as well as non-public utility generators in California selling through the ISO markets or using the ISO's transmission lines, to offer the ISO all of their capacity in real time during all hours if it is available and not already scheduled to run. This must-offer obligation does not apply to power scheduled to run under bilateral agreements. The must-offer obligation does not apply to hydroelectric power because of its multi-purpose limitations (e.g., irrigation, recreation, and power production). The must-offer obligation is designed to prevent withholding and thereby 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. The rehearing requests raise a number of issues that will be addressed below.

1. Applicability to Non-Public Utility Generators

A number of non-public utility entities request rehearing of the requirement that, because they make sales through the ISO's markets or use the ISO's interstate transmission grid (with the exception of hydroelectric power), they must offer all their available power in real time during all hours. They primarily argue that the Commission is overstepping its jurisdictional bounds by asserting jurisdiction over them in violation of section 205 of the FPA.

CMUA, SMUD, and others contend that the Commission lacks jurisdiction over municipalities and other state agencies. CMUA maintains that "as far back as 1998, CMUA members have voluntarily made units available to the ISO, have sold the ISO energy on a regular basis in response to reliability calls, and continue to sell to creditworthy buyers." CMUA at 8. CMUA contends that there is no evidence that such facilities are refusing unreasonably to sell in the ISO's markets.

The Commission denies the requests for rehearing. The Commission is not asserting jurisdiction over non-public utilities. Rather, as the Commission explained in the April 26 Order, it is exercising its conditioning authority to assure that all generators located in California, including non-public utility generators, that voluntarily sell into the ISO's spot market or that use the ISO's interstate transmission grid, offer their available power in California. [18] As we stated in the April 26 Order, if a non-public utility makes sales into the ISO's markets over which the Commission has exclusive jurisdiction or uses the ISO-controlled interstate transmission facilities, it must abide by the same conditions that are applicable to public utilities. [19] On rehearing, parties have raised no arguments that warrant a different result. We cannot meet our statutory responsibilities under the FPA to ensure just and reasonable rates in the Western spot markets if we allow non-public utilities to participate in the ISO's markets and use interstate transmission facilities, while refusing to comply with the measures necessary to ensure the justness and reasonableness of the ISO's rates and terms and conditions of service. In short, the Commission cannot ensure just and reasonable rates under the FPA unless non-public utilities, which sell power into the ISO's market or use the ISO's transmission lines, are subject to the same market rules as public utilities.

CAC/EPUC contends that imposing the must-offer obligation and the mitigation plan on QF facilities conflicts with the regulatory scheme established under the Public Utility Regulatory Policies Act of 1978 (PURPA). QFs that engage in sales for resale in interstate commerce and/or the transmission of electric energy in interstate commerce are public utilities and are therefore subject to the Commission's jurisdiction, although the Commission has exempted them from many provisions of the FPA. [20] However, because of the need for uniformity among all sellers, the Commission will not exempt QFs from the must-offer obligation and mitigation plan to the extent that QFs use the ISO's interstate transmission lines and make sales through the ISO's markets. [21] The exemptions from regulation granted pursuant to PURPA to QFs do not mean QFs must or should be exempted from the must-offer obligation.

2. Extent of the Must-Offer Obligation

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[18] San Diego Gas and Electric Company, et al., 95 FERC ¶ 61,115 at 61,356 (2001).

[19] Id. Since CMUA members already sell power on a regular basis to the ISO, and are assured of recovering their marginal costs when they run pursuant to the must-offer obligation, CMUA has not demonstrated that the Commission's actions would have an adverse effect on them.

[20] Section 210(e) of PURPA states the Commission shall prescribe rules under which QFs are exempt, in whole or in part, from the FPA, PUHCA, and from state laws and regulations respecting rates or financial or organizational regulation. 16 U.S.C. § 824a-3 (1994). The Commission exempted most QFs from portions of the FPA, 18 C.F.R. § 292.601 (2000), PUHCA, 18 C.F.R. § 292.601 (b) (2000), and from state laws and regulations respecting rates and financial and organizational regulation, 18 C.F.R. § 297.601 (c) (2000).

[21] CAC/EPUC filed a request to stay the application of the mitigation plan as applied to QFs. Given the resolution of the rehearing request, the request for stay is denied.

The predominant issue raised on rehearing is how to apply the must-offer obligation to thermal generators with environmental limitations on their operations. The April 26 Order stated that generators would not have to run if doing so would violate their certificate or applicable law. But it required those units to run if it involved only the paying of additional amounts to obtain emission credits to permit them to run outside their emission limitations.

A number of rehearings request clarification that generators do not have to run if doing so would violate certificates or subject them to possible criminal penalties or fines.[22] Sellers further maintain that units with maximum run limitations have legitimate opportunity costs that the Commission has failed to recognize.[23] They recognize that the issue of energy limited units is complex,[24] but that the Commission's proposed emission credit adder does not fully take into account the costs imposed by forcing these plants to run whenever the ISO determines. They argue that they have traditionally managed these units to ensure that they run only during the times of the year when they are most valuable and that they should not be required to run at other times without adequate compensation for the revenues they forgo.[25] Mirant maintains that exempting hydroelectric power from the must-run requirement while not exempting environmentally-limited gas units is discriminatory. Sellers maintain that the Commission should either eliminate the must-offer requirement or permit generators to include in their bids an amount to capture the economic value of losing the ability to generate in later years. Reliant maintains that application of the must-offer obligation to energy limited units should be conditioned on expansion of California Executive Order D-24-01 to sales into the ISO, so that run-time limits would not apply to such sales.

Municipals[26] similarly argue the Commission needs to make allowances for the possibility that imposing a must run obligation on a generator may impose additional price or cost risk at later periods of time. NCPA maintains that it is required to make use of its thermal plants to meet its member-customer needs and is concerned that if it is forced to run during particular periods, it may not be able to meet the power needs of its members in later periods, if it is unable to obtain additional emission credits. It therefore requests clarification that it not be required to honor the must offer obligation unless it is able to obtain additional air pollution credits and that it be permitted to include those credits in any

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[22] Rehearing Requests by MID, M-S-R, NCPA, TANC.

[23] Rehearing Requests by Dynegy, Mirant, Reliant.

[24] See Rehearing Request by Reliant.

[25] For example, Dynegy maintains that forcing its units to run today will require it to use up emission credits allocated for the year 2003, and that it should be reimbursed for the lost opportunity of being unable to run that unit in the year 2003.

[26] Rehearing requests by NCPA, NRECA.

bid it makes into the ISO. Municipal generators request clarification that they do not have to make power available to the ISO when that power is being used to serve their own retail load or is required as reserves under interconnection agreements.[27] They contend that the April 26 Order was not clear whether the requirement to serve retail loads would be considered the equivalent of bilateral contracts. CAC/EPUC contends the must-offer obligation should not be applied to QF facilities, because it interferes with the QF's obligation to its thermal host, which is governed by a contract or operational protocol. Calpine similarly argues that QF units with capacity committed to a utility are not subject to the must-offer even if it chooses not to operate at maximum capacity.

The Commission clarifies that generators should not be exempt from the must-offer requirement absent a showing that running the unit violates a certificate, would result in criminal violations or penalties, or would result in QF units violating their contracts or losing their QF status. Many of these issues are within the domain of the State of California, and we strongly urge California to modify current policies to enable generators to run during this period of scarce supply. For municipal generators the must-offer obligation applies only to available power remaining after the municipality satisfies its own retail load and contractual obligations. Given the shortage of power in California, all generators in California, including municipals, should not hold energy in reserve (over minimum acceptable levels) when the energy is needed to meet demand.

For QF facilities, like other generators, the must-offer obligation applies to energy that is available from generation that is not already contractually committed or would not violate its contractual obligation to its thermal host. With respect to Calpine's argument, a QF with capacity committed to a utility is, therefore, subject to the must-offer obligation if it chooses not to sell its maximum output to the utility. With respect to CAC/EPUC's contention, the Commission has granted waivers of the operating and efficiency standards so that QFs, without jeopardizing their QF status, can generate power

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[27] MID, M-S-R, TANC.

regardless of whether the host needs thermal energy. [28] Therefore, QF facilities will be expected to produce available energy regardless of whether the host requires thermal energy.

Due to the severity of the power shortage in the WSCC in general, and in California specifically, the Commission finds that the incurrence of expenses for obtaining additional emission allowances is not a valid reason to withhold available energy from the ISO's market. As discussed later in this order, the Commission is providing a mechanism for generators that incur emission related expenses to recover those costs through the ISO. Moreover, the Governor of California signed an Executive Order, D-40-01, allowing generators to exceed their emission runtimes without losing valuable future emission allowances, provided the energy is sold to DWR (or another California buyer) or dispatched by the ISO. Therefore, exceeding today's emission limits will not affect future limits. Thus, Executive Order D-40-01 moots all arguments on this issue insofar as California generators are concerned, including those of the municipal generators.

3. Withholding Generation for Operational Reasons

Mirant, Reliant, and Williams maintain that the must-offer obligation fails to recognize the need to withhold generation to cover the possibility that a unit will unexpectedly go offline. They take issue with the statement in the April 26 Order that a generator cannot be financially harmed from offering all of its units because the generator will only have to pay for the cost of replacement power, which is the same amount the generator would earn if the unit ran. They argue that, while this statement is true in theory, it does not apply to the ISO's markets because due to penalties in the ISO's tariff and the manner in which the ISO computes the cost of replacement energy, the generator would have to pay more for replacement energy than it would receive for the unit's bid in the market.

The must-offer obligation is crucial to ensuring that all capacity is in the market when needed and tariff provisions should not inhibit the fulfillment of this obligation. The Commission finds that during

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[28] See San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, 93 FERC ¶ 61,238 at 61,772 & n.3 (2000) (December 8 Order)(granting temporary waiver of QF regulations); San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, 93 FERC ¶ 61,294 at 62,018 (December 15 Order)(extending waivers); Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States, 94 FERC ¶ 61,272 at 61,970-71 (March 14 Order)(extending QF waivers); Further Order Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States, 95 FERC ¶ 61,225 at 61,767-68 (2001) (May 16 Order)(waivers extended to entire WSCC and through April 30, 2002). In a second order issued on May 16, the Commission required California Utilities to provide interconnection and transmission service to QFs pursuant to existing agreements to permit certain sales of QF power to third-party purchasers. San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, 95 FERC ¶ 61,226 (2001).

the periods mitigation is in effect, the current ISO tariff provisions in this regard are unjust and unreasonable, and, therefore, we will require the ISO to modify its tariff, to be effective the day after the date of this order, so that the only penalty for having a unit forced out of service is the cost of replacement energy. The must-offer obligation modifies various market rules that existed when the current penalty provision was accepted for filing.

4. Other Issues

Several rehearing requests are concerned about generators avoiding the must-offer requirement through so-called "megawatt laundering" where a generator sells power to an out-of-state marketer, who then reimports that power to avoid a mitigated price. [29] The Commission clarifies that the must offer obligation applies to all sellers who own or control generation by contract. Moreover, the mere fact that a generator has a contract to provide power to a marketer does not exempt the generator from the must-offer obligation for energy that the marketer is not scheduling. As long as the generator has available energy, the generator has the obligation to offer that power into the ISO's auction market. Moreover, as described later, all marketers in the ISO's markets must now be price takers and cannot justify a bid higher than the mitigated price.

Dynegy maintains the must-offer obligation should be limited to emergency hours only. It argues that had this obligation been imposed at the time it purchased the plants, it would have paid a lower amount. It therefore contends the must-offer obligation unfairly changes the contractual conditions under which it purchased the plants. The Commission rejects Dynegy's argument. The must-offer obligation must be applied in all hours in order to ensure that all available capacity is in the market and that none is being withheld, except for the reasons previously discussed. Moreover, mitigation is now being applied in all hours, so the must-offer obligation must also be applied to all hours.

LADWP requests clarification that the must-offer and price mitigation aspects of the order do not apply to its sales of energy under bilateral contracts or to sales or purchases that are scheduled to run in real-time pursuant to a bilateral contract. All public and non-public utilities which control generation in California must offer power in the ISO's spot markets. This requirement applies to any non-hydroelectric resource whether owned or under contract only to the extent its output is not scheduled for delivery (or committed for minimum operating reserves) in the hour. All public and non-public utilities in the remainder of the WSCC must offer in a spot market of their choosing any non-hydroelectric resource whether owned or under contract to the extent its output is not scheduled for delivery (or committed for minimum operating reserves). All sales in these spot markets are subject to the price mitigation established in this order.

[29] Rehearing Requests by ISO, CMUA, Metropolitan, NCPA, SMUD, San Diego, Edison.

The rehearing requests raise issues with respect to the effect of the must-offer obligation on the ISO's authority to curtail exports of power to other markets. Reliant and Mirant maintain the must-offer requirement should supplant the ISO's curtailment authority under its tariff. Reliant contends the curtailment authority is unnecessary now that California generators will be bidding all available supply into the real-time market. Williams maintains the ISO should compensate generators for curtailments. SDG&E, on the other hand, contends the Commission should permit the ISO to curtail in-state generation destined for other states.

The Commission is not persuaded to change the ISO's curtailment authority at this time. Since Reliant maintains that this authority is no longer needed as a result of the must-offer obligation, it has not demonstrated how it is harmed by leaving the current authority intact. The price mitigation adopted in this order establishes the same price throughout the WSCC as in California, and therefore does not provide a financial incentive for generators to sell energy outside of California. Parties may renew objections to this authority in future proceedings if they can establish discernible harm.

C. Demand Response

The April 26 Order provided that beginning on June 1, 2001, each public utility purchasing electricity in the ISO's real-time market is required 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 ISO requests clarification as to whether the demand response mechanism is voluntary or mandatory. If voluntary, the ISO maintains that it is already implementing a number of demand response mechanisms. If the requirement is mandatory, a number of rehearing requests contend that it is insufficient to solve the problem, [30] and is technically infeasible, in the short-run, because there is no mechanism for obtaining accurate demand response signals from all customers. In addition, the ISO cannot currently curtail power to individual loads. [31] Parties assert that load serving entities should not be required to simply guess at the prices its customers are willing to pay. SDG&E, for example, contends that the CPUC did not permit it to act as an aggregator for demand responses, and accordingly it would simply be guessing at what price its customers are willing to pay. San Francisco maintains that curtailing retail customers is anathema to the Load Serving Entities' (LSEs') duty to serve. A number of requests contend that demand response is a state concern, and the Commission has no authority to indirectly regulate retail customers. Others contend that since the DWR is not a public utility, it would not be covered by the demand response mechanism in any event.

On the other hand, generators maintain that a demand response mechanism is crucial to establishing a viable market and is needed to provide generators with appropriate scarcity rents.

[30] See Rehearing Request by CMUA,

[31] Rehearing Requests by ISO, DWR, San Francisco.

The Commission continues to believe that establishing a demand response mechanism is crucial to establishing a robust market. [32] Without a demand response mechanism, the ISO is forced to work under the assumption that all customers have an inelastic demand for energy and will pay any price for power. There is ample evidence that this is not true. Many customers, given the right tools, can and will manage their demand. Such an assumption inevitably leads to higher prices during times of shortage, since high supply bids do not lead to a reduction in power purchased. A working demand response program puts downward pressure on price, because suppliers have additional incentives to keep bids close to their marginal production costs and high supply bids are more likely to reduce the bidder's energy sales. [33] Appropriate price signals to customers thus helps to mitigate market power as high supply bids are more likely to reduce the bidders' energy sales. Suppliers thus have additional incentive to keep bids close to their marginal production costs. Demand-side price-responsive bids will also help to allocate scarce supplies efficiently.

Indeed, without demand-side price responsiveness, there can be no market mechanism for ensuring that scarce supplies are allocated to the highest valued uses during shortages. However, based on the technical impracticalities raised in the rehearing comments, the Commission does not find that the demand response requirement should be implemented at this time. Because the development of demand response is so critical, we expect that buyers in the ISO's market will submit demand bids as soon as demand bidding becomes technologically feasible. Meanwhile, the Commission will continue to monitor developments in California to determine whether additional Commission action is needed. The ISO must include in its quarterly reports a discussion of all demand response changes that have been implemented. If state programs for demand response do not develop, the Commission expects the ISO to enhance its own programs. [34]

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[32] See Chandley, Harvey, & Hogan, Electricity Market Reform in California, at 25 ("The least controversial reform of market design would be to implement all the changes needed to allow for demand side response in the face of higher prices." (Attached to November 22, 2000 Comments of SDG&E).

[33] Already conservation has helped to reduce demand. See Peter Behr, "Fears of an Energy Crisis Begin to Dim, Consumption Cuts Help Lower Prices for Gasoline, Natural Gas and Electricity," Washington Post, April 8, 2001, at E1 (California has reduced demand 8%). A properly designed demand side response program could improve this performance even more markedly by providing price incentives for reduction.

[34] Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States, 94 FERC ¶ 61,272 at 61,972-73(March 14 Order) (DSM programs); Further Order Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States, 95 FERC ¶ 61,225 (2001) (May 16 Order).

Public utilities along with California officials also must actively pursue such approaches to achieving a viable demand response program. As SDG&E points out, LSEs can effectively act as aggregators for retail demand response. SDG&E and other public utilities should continue to pursue demand response initiatives and are required to file with the Commission by September 14, 2001 a report of the progress that is being made in establishing these mechanisms and any difficulties they have encountered.

To help facilitate these initiatives, the Commission intends to conduct a staff technical conference to explore how demand response can be increased. The first purpose of the conference will be for the Commission to familiarize itself with the status and availability of conservation, demand-side management, and other innovations to help communicate real-time price signals to consumers, including the software and metering necessary to support such programs. The second purpose will be to explore how these programs can be implemented. At the conclusion of the conference, the Commission will reconsider the feasibility and schedule for a demand bidding requirement and its use in establishing prices in the ISO's market.

D. Price Mitigation for California and the WSCC

The April 26 Order applied price mitigation to periods of reserve deficiency, defined as those periods beginning with Stage 1. Under the approach set forth in the April 26 Order, the ISO would conduct a market clearing auction for its real-time markets. During periods of reserve deficiency, however, the ISO would calculate a marginal cost bid for each generator by using a proxy for the gas costs, emission cost, and operation and maintenance (O&M) expenses. The ISO would then use the bid of the last unit dispatched to establish the market clearing price. The justification for this approach is that as reserves are reduced, all sellers are aware of how tight supplies are relative to the amount they have to offer. Thus, sellers have an incentive to offer supply at prices above that which they would ordinarily bid. Because of the imbalance of supply and demand, these prices may not be just and reasonable. The Commission, however, did not impose mitigation during periods of reserve sufficiency because there is less risk that prices would exceed those charged in a competitive market. During reserve sufficiency conditions a supplier has less of an incentive to bid a high price, because it cannot be sure it will be dispatched, since other generators may offer lower bids.

Many rehearing requests, as well as comments in the West-Wide proceeding, contend the Commission should have extended mitigation to cover all hours. They contend that evidence from a number of studies shows that sellers have been able to exercise market power during all hours. They contend that the Commission has the obligation under the FPA to assure just and reasonable rates in all hours. [35] Duke Energy and other generators insist that the record does not show that market power has been exercised.

As described earlier, the Commission here is instituting a two-part approach to price mitigation for spot markets to cover all hours for California and the WSCC. Because these markets are integrated, the mitigation proposal must establish the same prices for all markets in order to prevent arbitrage where power is diverted from the lower priced market to the higher priced. The mitigation plan further has to recognize the differences between the California market, which has an organized auction, and the remainder of the WSCC, which does not have a similar centrally organized market. The plan adopted by the Commission is tailored to provide a uniform scheme of mitigation that at the same time recognizes the differences between these markets. During non-reserve deficiency hours in California, the Commission will adapt the ISO's market clearing price for spot market use West-wide.

The purpose of instituting this dual plan is to stabilize the market in the short-term and permit California time to repair its market mechanisms. The shortage of hydroelectric power together with the failure to build efficient generation is clearly a major part of the problem. This has been exacerbated by the imbalance between high wholesale prices and low retail prices, which do nothing to dampen demand. What is clear, however, is that a major contributor to the high prices was the deficient market mechanisms initially established by California, and approved by the Commission, that have resulted in a dysfunctional marketplace both in California and the remainder of the West. The mitigation plan established in this order, in effect, provides breathing room for the markets to right themselves.

The ISO, CPUC, and PG&E further contend that mitigation should apply outside of the ISO's Imbalance Energy market and should include its Day-Ahead and Hour-Ahead markets for ancillary services and its congestion management market. The Commission's order providing clarification and preliminary guidance addressed these issues. [36]

Several rehearing requests contend the mitigation should apply to all bilateral contracts. [37] The section 206 proceeding involving the ISO was limited to the ISO's and PX's real-time markets and did not extend to bilateral markets.[38] As discussed, however, in the Commission's section 206 investigation of the non-ISO spot markets in the WSCC, we have determined it appropriate to also

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[35] Rehearing Requests by ISO, CEOB, CMUA, Assembly, City of Anaheim, et al., CFA, Metropolitan, PG&E, NCPA, SDG&E, San Diego, San Francisco, Seattle, Edison, SCWC.

[36] San Diego Gas & Electric Company, et al., 95 FERC ¶ 61,275 (2001).

[37] Rehearing Requests by CPUC, City of Anaheim, et al., PG&E.

[38] San Diego Gas & Electric Company, et al., 93 FERC ¶ 61,121, at 61,349 (2000) (limited proceeding to real-time markets).

apply mitigation to the bilateral spot markets in the WSCC, including California. Parties have not provided justification for extending the scope of our investigation or the mitigation to bilateral transactions other than spot markets. Moreover, any mitigation applied to the ISO's real-time markets will, over time, impact bilateral and forward markets as well.

A number of parties argue that the Commission's market monitoring and mitigation plan will not result in just and reasonable rates as required by the Federal Power Act, and the Commission should either return to individual cost-of-service rates or condition the continued use of market-based rates on effective mitigation measures. [39] The CPUC maintains that because the Commission found rates to be unjust and unreasonable, the Commission is required to fix by order just and reasonable rates. It declares that "[w]here, as here, market power is pervasive through the industry in the west, FERC must impose cost of service pricing." [40] PG&E asserts that the Commission should immediately suspend the existing market-based rates of all sellers in the West and that the Commission should require immediate cost of service filings. [41] CEOB maintains that "[t]he Commission has no choice but to engage in cost-based ratemaking, or to adopt a sweeping mitigation scheme throughout the WSCC to ensure just and reasonable rates...." [42]

Since determining that the market structure and rules for wholesale sales of electric energy in California had caused, and continued to have the potential to cause, unjust and unreasonable rates for short-term energy during certain times and under certain conditions, the Commission has ordered changes to the market structure and rules to assure that future rates would be just and reasonable. [43]

After carefully considering the record, the Commission reaffirmed its general finding that, as a result of the seriously flawed electric market structure and rules for wholesale sales of electric energy in California, unjust and unreasonable rates were charged, and could continue to be charged during

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[39] See, e.g., ISO, CEOB, CPUC, Assembly, CFA, PG&E, San Francisco, Seattle, and Edison.

[40] CPUC Request for Rehearing at 7.

[41] PG&E Request for Rehearing at 13-15.

[42] CEOB Request for Rehearing at 4.

[43] FERC's remedial measures "must be construed as a whole in assessing FERC's compliance with FPA § 206". In re California Power Exchange Corp., 245 F.3d 1110, 1120 (9th Cir. 2001).

certain times and under certain conditions , unless certain targeted remedies were implemented. San Diego Gas & Electric Co., et al. 93 FERC ¶ 61,294 (2000)("December 15 Order"). [44]

The following remedies were adopted by the Commission in order to correct the specific flaws identified through the investigatory and hearing process: (1) because "the mandatory participation requirement . . . [was] producing rates that [were] not just and reasonable during certain periods," the Commission eliminated the requirement that the IOUs sell all of their generation into and buy all their energy needs from, the PX; (2) recognizing that it could assure the justness and reasonableness of California wholesale markets prices only by eliminating the PX's exclusive mandatory exchange, the Commission terminated the PX's wholesale tariffs; (3) to eliminate market participants' chronic underscheduling with the ISO, which jeopardized ISO system operations and created a strong sellers' market and higher prices in the most volatile spot market (real-time imbalance), the Commission required market participants to preschedule 95 percent of their load, with penalties for scheduling deviations in excess of five percent of an entity's hourly load requirements and disbursements of penalty revenues to all loads scheduled accurately; (4) mindful that eliminating the mandatory buy/sell requirement would move a considerable amount of load into the forward long-term markets all at once, the Commission established, effective for one year, an advisory benchmark for pricing five-year contracts; (5) because of concerns about the independence and effectiveness of the ISO governing board, the Commission ordered that the current stakeholder governing board be replaced by a non-stakeholder board composed of members independent of market participants; and (6) the Commission required the ISO and the IOUs to file generation interconnection procedures to facilitate the interconnection of new generators or existing, upgraded generators, thereby enhancing system reliability and reducing price volatility.

To further assure that prices in the ISO's and PX's spot markets are just and reasonable, the Commission directed that a technical conference be held to develop a comprehensive and systematic monitoring and mitigation program to be submitted to the Commission by March 1, 2001. Until that date, the Commission established an interim $150/MWh breakpoint for spot market sales. On an interim basis, all public utility sellers bidding at or below $150/MWh would receive the market clearing price up to $150/MWh, and only those sellers bidding above $150/MWh would receive their actual bid

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[44] The Commission has freedom, "within the ambit of [its] statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances. "FPC v. Natural Gas Pipeline Co., 315 U.S. 575, 586 (1942); In re California Power Exchange Corp., 245 F.3d at 1120 . FPA § 309, 16 U.S.C. § 825h, gives the Commission the necessary flexibility to take unusual remedial action in appropriate circumstances. See Permian Basin Area Rate Cases, 390 U.S. 747, 776 (1968) (applying NGA § 16, the counterpart of FPA § 309, the Court held that "the Commission's broad responsibilities . . . demand a generous construction of its statutory authority."); FPC v. Louisiana Power & Light Co., 406 U.S. 621, 642 (1972)(same).

price. However, all accepted bids above $150/MWh were required to be reported to permit proper monitoring and review by the Commission.

On April 26, 2001, the Commission adopted a prospective monitoring and mitigation plan for real-time California wholesale electric markets which replaced that previously in effect. The Commission's plan: (1) enhanced the ISO's ability to coordinate and control planned outages; (2) required sellers with PGAs, as well as non-public utility generators located in California that voluntarily make sales through the ISO's markets or 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; (3) required 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; (4) established 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; (5) required 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; (6) established 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, beginning at a Stage 1 alert (i.e., when reserves are below 7 percent). This mechanism provided a formula (based on gas-fired generation) for the ISO to use to establish the real-time market clearing price when mitigation applies. Higher bids were permitted if they could be justified.

In this order, the Commission is expanding the market monitoring and mitigation plan to produce spot market prices in all hours that are just and reasonable and emulate those that would be produced in a competitive market. We find that a return to individual cost-of-service ratemaking is unwarranted. As addressed above, the market changes and monitoring procedures already implemented by the Commission have improved the wholesale power markets in California. This order continues that effective course. In contrast, cost-of-service ratemaking tends to penalize more efficient generators and not provide proper incentives for generators to become more efficient, since each generator's price is dependent on its costs. [45] Moreover, individual cost-of-service rates may not provide generators with appropriate scarcity rents. Establishing individual cost-of-service rates is also difficult with respect to spot markets. For peaking units, decisions would need to be made about the number of projected MWhs over which to spread costs. Generators also would have to make filings establishing their rate base, acceptable rate of return, and cost-of-service, possibly including trackers for volatile costs such as gas and emissions fees. Resolving the issues involved in such filings would be protracted and would not provide price certainty to the market. We do provide for any generator unable to work within the revised mitigation framework the opportunity to apply for cost-based rates for the duration of the plan.

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[45] See National Rural Telecom Association v. FCC, 988 F.2d 174, 178 (D.C. Cir. 1993).

The monitoring and mitigation plan adopted by the Commission in this order satisfies the requirements of the FPA. In particular, FPA Section 206 allows the Commission to determine whether "any rate, charges, or classification . . . or any rule, regulation, practice, or contract affecting such rate, regulation or classification" is unjust or unreasonable, and to fix "the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force." 16 U.S.C. § 824e(a)(1994). In this order, as in our earlier orders related to this matter, the Commission has examined the rules, regulations, practices and contracts that are currently being used, and made changes that are necessary to prevent possible abuses that could lead to unjust and unreasonable rates.

The focus on changes to the existing market structure, rather than on setting cost-of-service rates for individual sellers, is consistent with the case law. As the Supreme Court made clear, it "has never held that the individual company cost-of-service method is a sine qua non of natural gas [or electric] rate regulation." [46] Nor has the Court limited ratemaking agencies "to the service of any single regulatory formula; they are permitted, unless their statutory authority otherwise plainly indicates, 'to make the pragmatic adjustments which may be called for by particular circumstances.'" [47] The success of a particular ratemaking approach is judged by "the result reached not the method employed." [48] The end result of any ratemaking order must be to provide rates within a zone of reasonableness that "take fully into account the probable consequences of a given price level for future programs of exploration and development". [49] As that language makes clear, a cost-based inquiry alone would not be sufficient in these circumstances to fulfill the statutory duty. Rather, the Commission must consider the broader public interest, and, in particular, the interest in setting rates that will assure adequate supply. [50]

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[46] Wisconsin v. FPC, 373 U.S.294, 309 (1963).

[47] Permian Basin Area Rate Cases, 390 U.S. 747, 776-77 (1968).

[48] FPC v. Hope Natural Gas Company, 320 U.S. 591, 602 (1944).

[49] Permian Basin, 390 U.S. at 797; see Atlantic Refining Co. v. Pub. Service Comm., 360 U.S. 378, 388 (1959) (same) .

[50] Permian Basin, 390 U.S. at 796-97; Mobil Oil Corp. v. FPC, 417 U.S. 283, 317-18 (1974); Consumers Union v. FPC 510 F.2d 656, 660 (D.C.Cir. 1974); see also Central Iowa Power Coop v. FERC, 606 F.2d 1156, 1165 n. 28 (D.C.Cir. 1979) (affirming rate based on "need to stimulate short-term purchases of excess capacity in lieu of adding new capacity and to discourage reliance on emergency energy when units are less than efficient").

The Commission is free to adopt market-based rates. [51] In adopting market-based rates, the Commission must: (1) provide a clear and reasoned analysis of the need for market-based pricing to promote the statutory objectives of the FPA; (2) support its decision with substantial evidence; and (3) assure that the resultant market-based rate falls within a "zone of reasonableness." [52] Having adopted a market-based approach for the California market, nothing requires the Commission to revert to a cost-of-service ratemaking approach whenever it finds flaws in the market structure. See Environmental Action v. FERC, 996 F.2d 401, 411(D.C. Cir. 1993) (finding that the Commission "has never bound itself to a rule requiring either rigid regulation or textbook markets"). The courts have also approved the use of marginal cost pricing as an appropriate regulatory tool. Town of Norwood v. FERC, 962 F.2d 20, 22 (D.C. Cir. 1992) (stating "one of the best-established precepts of classical economics: social welfare is maximized when the marginal cost of purchasing any commodity is equivalent to the marginal cost of producing it.") See Electricity Consumers Resources Council v. FERC, 747 F.2d 1511 (D.C. Cir. 1984) (same).

Rather, in such circumstances, the presence of a monitoring program under which the Commission can take appropriate action to restructure the market is key. For example, in Elizabethtown, the court found that the continued "exercise of the Commission's NGA] § 5 authority . . . to assure that a market (i.e., negotiated) rate is just and reasonable" sufficiently safeguards against abuses under a market pricing approach. 10 F.3d at 870. Similarly, in Environmental Action, the court approved the combination of price ceilings and complaint procedures as sufficient safeguards because that would allow "competitive forces, not market power, [to] determine most transaction prices . . . and

[51] E.g., Louisiana Energy and Power Authority v. FERC, 141 F.3d 364 (D.C. Cir. 1998); Elizabethtown Gas Company v. FERC, 10 F.3d 866, 870 (D.C. Cir. 1993); see also Midcoast Interstate Transmission, Inc. v. FERC, 198 F.3d 960, 968 (D.C.Cir. 2000). Other agencies subject to ratemaking regimes similar to that of the FPA have been upheld in adopting a market-based, rather than a cost-of-service, approach to setting rates. See Nat'l Ass'n of Regulatory Util. Comm'rs v. FCC, 737 F.2d 1095, 1137 (D.C. Cir. 1984); Nat'l Rural Tel. Ass'n v. FCC, 988 F.2d 174 (D.C. Cir. 1993); Consolidated Rail Corp. v. U.S., 812 F.2d 1444 (3d Cir. 1987); Potomac Elec. Power Co. v. ICC, 744 F.2d 185 (D.C.Cir. 1984).

[52] In Farmers Union Central Exchange, Inc. v. FERC, 734 F.2d 1486 (D.C. Cir. 1984), cert. denied sub nom. Williams Pipe Line Company v. Farmers Union Central Exchange, Inc., 469 U.S. 1034 (1984), the court explained that it may not invalidate "rate orders that fall within a 'zone of reasonableness,' where rates are neither 'less than compensatory' nor 'excessive.'" It added that "when FERC chooses to refer to non-cost factors in ratesetting, it must specify the nature of the relevant non-cost factor and offer a reasoned explanation of how the factor justifies the resulting rates."

serve to extend competitive pricing to situations where market power might otherwise prevail." 996 F.2d at 413. [53]

Through the remedies ordered in earlier orders and herein, the Commission determined and is continuing to determine pursuant to FPA Section 206 "the just and reasonable rate, charge, classification, rule, regulation, practice, or contract" to replace flawed structure and rules, and to "fix the same by order." The Commission was not obliged to set seller-specific cost-based rates to resolve the perceived problems, given its continuing monitoring and review of the situation which offers adequate safeguards against potential market abuse. The mitigation plan adopted in this order relies on market solutions and mechanisms to the maximum extent possible, consistent with the Commission's statutory responsibilities to maintain just and reasonable rates. The revisions made in this order are designed to provide a structure that will minimize potential market power abuses, thus lowering customer rates, while also encouraging adequate supply in the market for the immediate future.

E. ISO Market Clearing Auction During Periods of Reserve Deficiency

Under the April 26, 2001 mitigation plan, 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. The ISO would 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/MWh adder for O&M expenses. The gas cost proxy was based on an average of the daily prices published in Gas Daily for all California delivery points. The emission cost was to be calculated by the ISO using emissions costs from Cantor Fitzgerald Environmental Brokerage Services and the emissions rate for the unit. All generators would be paid a single market clearing price reflecting the last unit dispatched calculated using the proxy prices.

Rehearing requests addressed a number of elements of this plan. Based on those rehearing requests, the Commission, as discussed in detail below, is modifying the method of determining the cost for gas, the treatment of emission costs, and the O&M adder. The Commission will address below the rehearing requests with respect to the ISO auction mitigation plan.

1. Use of the Marginal Cost of the Last Unit Dispatched

[53] The courts have approved market pricing for other agencies if available remedies assure that market power will not be abused. E.g., Ford Motor Co. v. ICC, 714 F.2d 1157, 1158-59 (D.C. Cir. 1983); Arkansas Power & Light v. ICC, 725 F.3d 716, 718 (D.C. Cir. 1984); Coal Exporters Ass'n v. U.S., 745 F.2d 76, 80 and 90 n. 18 (D.C. Cir. 1984); Arizona Public Service Co. v. U.S., 742 F. 2d 644, 647 (D.C. Cir 1984).

PG&E maintains the Commission should not determine price using the marginal cost of the last unit dispatched. Instead, it maintains the Commission should use the heat rate of the average cost unit. PG&E maintains that in a competitive market, each unit of generation would recover only its own marginal costs.

In a competitive market, however, each generator would not receive only its own marginal cost, as PG&E asserts. Competitive markets clear at a single price, which is effectively set by the marginal cost of the last unit produced. All more efficient units will receive the same price, which creates an incentive for firms to increase their efficiency. Therefore, using the marginal cost of the least efficient generating unit dispatched best replicates prices in a competitive market. In 1998 and 1999, when the California spot markets were producing average annual wholesale prices of $29 and $31 per MWh, respectively, the marginal cost of the last unit dispatched set these prices. The mitigation plan simply returns the market to the competitive principles that existed in 1998-99.

The ISO contends that inflexible units such as combustion turbines should not set the proxy price, because they do not have the flexibility to be dispatched on a 10-minute basis. The Commission's mitigation plan is based on the payment of the marginal cost of the last generator dispatched to serve the last increment of load. Therefore, if a combustion turbine is the last generator dispatched, its bid should establish the market clearing price.

2. Calculation of Market Clearing Price

Rehearing requests raise a number of issues with respect to the calculation of the mitigated price, particularly with respect to the gas prices and emission prices used.

a. Gas Costs

Under the Commission's April 26, 2001 approach, gas costs used in the formula are determined by an average of reported daily spot gas prices at California delivery points. The requests for rehearing raise a number of issues regarding the use of gas costs to determine the market clearing price. Several rehearing requests contend that the Commission should not use proxy prices, but should use actual gas (and emissions) costs for generators.[54] Others contend that using the reported gas prices overstates gas costs, because generators have a portfolio of gas supplies and are not buying all their gas at spot prices.[55] The ISO and CEOB contend that to better reflect supply portfolios, the Commission should use monthly bid-week gas prices, rather than daily spot prices. The ISO recommends the Commission use bid-week monthly prices from Gas Daily, but for only three points in

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[54]Rehearing Requests by NCPA, Seattle, Edison.

[55]Rehearing Requests by ISO, CPUC, Assembly, Metropolitan, PG&E, SDG&E, San Diego, San Francisco, Edison.

California, Malin, SoCal Gas (large packages), and PG&E city-gate (excluding PG&E large packages). Others contend that using the average gas price does not accurately reflect the marginal costs of generators, because gas prices are higher at the Southern California points than Northern California points. [56] They suggest that the gas proxy price should be revised to more accurately reflect the marginal costs of each generator.

The Commission's mitigation plan is designed to establish generators' bids and market prices up-front. Using actual costs to determine marginal cost, as some suggest, would not establish generator bids, but would require an after-the-fact review of whether a generator's bid actually reflected its marginal cost. Using actual costs, therefore, would not provide price transparency, and would be administratively infeasible because it would require a constant reevaluation of every generator's bids.

The Commission will revise the spot gas prices to be used in the formula to accord with the requests by the ISO to establish the proxy gas cost for determining marginal costs.[57] The ISO will be required to average the mid-point of the monthly bid-week prices reported by Gas Daily for three spot market prices reported for California.[58] This price represents a reasonable proxy for the marginal cost that generators will incur, since they can pre-buy their gas requirements for the month at this price.[59]

The Commission recognizes that, as Reliant and Dynegy point out, spot gas prices in southern California off of SoCal Gas's system exceed other spot prices in California. The staff of the California Energy Commission has recognized that a chief contributor to the high natural gas prices in southern California is the deficit of intrastate capacity on the SoCal Gas system.[60] It reports that the interstate delivery capability exceeds the ability of SoCal Gas to receive that gas by 300 MMcf/d. It concludes that:

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[56] Rehearing Requests by CEOB, Dynegy, Reliant, Williams.

[57] See Norwood v. FERC, 962 F.2d 20, 22 (D.C. Cir. 1992) (one of the best established principles of classical economics: social welfare is maximized when the marginal cost of purchasing any commodity is equal to the marginal cost of producing it); Electricity Consumers Resources Council v. FERC, 747 F.2d 1511 (D.C. Cir. 1984).

[58] The three points are SoCal Gas (large packages), Malin, and PG&E city-gate.

[59] The average for June as reported in the Gas Daily Price Guide is $9.10. The bid-week monthly index prices are SoCal Gas (large packages) $11.71, Malin $5.98, PG&E Citygate $9.61.

[60] California Energy Commission Staff Draft Report, Natural Gas Infrastructure Issues, Docket No. 00-CEO-Vol -I, at 43 (May 17, 2001).

> this deficit in receipt capacity contributes to the high natural gas prices in California and the tight supplies to meet natural gas demand by electric generators.[61]

Another contributing factor to the high gas prices is the inability of generators and other shippers to acquire firm transportation rights on SoCal Gas's backbone system and SoCal Gas's system of allocating transportation on its backbone system, which leads to great uncertainty in scheduling gas supplies from interconnecting pipelines. This Commission recently has taken action to help improve the certainty of nominations on interstate pipelines into southern California,[62] but in the absence of scheduling changes on SoCal Gas, the Commission's changes to interstate scheduling practices cannot remove this uncertainty altogether. The Commission staff held a technical conference on May 24, 2001 to examine the problems in California gas infrastructure in which many participants continued to express concern about the lack of intrastate capacity on SoCal Gas and the difficulty in achieving certainty in scheduling gas supplies due to SoCal Gas's allocation procedures.[63] The Commission also is continuing to pursue efforts to try to dampen these higher prices into southern California. For example, the Commission recently issued orders requesting comment on whether to establish reporting requirements to create greater transparency in the gas market for southern California and whether imposing a price ceiling on capacity release transactions would have an effect on dampening prices.[64] The Commission will continue to monitor the situation in California to see whether further efforts are needed.

In addition to the dysfunction in southern California gas markets, the Commission cannot be certain that the daily SoCal Gas (large packages) spot price represents the actual cost of southern California generators. Gas Daily and the other reporting services do not indicate what volume moves at these prices, how much volume may be sold at lower prices in non-spot markets, and whether generators may be able to use other options to protect themselves against such higher prices.

Because of these concerns about the supplies coming into California from SoCal Gas, the Commission does not find it reasonable to base the market clearing energy price for California and the

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[61] California Energy Commission Staff Draft Report, Natural Gas Infrastructure Issues, Docket No. 00-CEO-Vol -I, at 43 (May 17, 2001).

[62] Amoco Energy Trading Corp. v. El Paso Natural Gas Company, 93 FERC ¶ 61,060 (2000), aff'd 94 FERC ¶ 61,225 (2001).

[63] California Natural Gas Transportation Infrastructure, Docket No. PL01-4-000.

[64] Order Proposing Reporting Requirement on Natural Gas Sales to California Market and Requesting Comments, 95 FERC ¶ 61,262 (2001); San Diego Gas & Electric Company, et al., 95 FERC ¶ 61,264 (2001).

remainder of the WSCC solely on the southern California spot price for gas. Instead, the most equitable way of handling this issue is to use the approach described above. Under the mitigation plan adopted in this order, individual southern California generators are permitted to justify bids above the market clearing price so long as they can show their entire gas portfolio justifies such a bid.

b. Emission Costs

The April 26 Order stated that the emission cost would be calculated by the ISO using emissions costs from Cantor Fitzgerald Environmental Brokerage Services and the emissions rate for each unit. Many rehearing requests point out that the method of paying for exceeding emission allowances has been changed, so generators no longer can buy NOx emissions when they run out of emission allowances. Instead, local air districts now require generators to pay mitigation fees when they exceed their emission allowances.

Several rehearing requests contend that the emissions cost should not be included as part of the proxy price, but should instead be collected in an up-lift charge when actually incurred.[65] Several also argue that not all generators pay emission costs and those that do incur such costs pay them only when they have used up their emission allotments.[66] They contend, therefore, that emissions costs should not be included until they have to be paid. ARB maintains that mitigation fees are not variable costs and should not be included in the marginal cost calculation because it will increase prices to all customers. It also argues that including mitigation fees as part of marginal costs will result in increased pollution as air districts may decide to reduce the emissions fees as a result of the higher consumer costs for power.

Sellers, on the other hand, contend that emissions costs are legitimately included as marginal costs.[67] They maintain that in running beyond their allotment of emission costs today, they not only are required to pay mitigation fees, but their emission allotments in subsequent years are reduced.[68] Sellers claim they need reimbursement for the opportunity costs of losing the ability to run their units in later years.

We will eliminate NOx costs from the calculation of the mitigated market clearing price. Since the Commission issued the April 26 Order, the SCAQMD's RTC program for electric generators larger than 50 MW (which was publicly traded by Cantor Fitzgerald Environmental Brokerage

[65] Rehearing Requests by ISO, ARB, CEOB, CPUC, Assembly, PG&E, San Diego, SCAQMD, Edison, SCWC.

[66] Rehearing Requests by Assembly, PG&E, Edison, SCWC.

[67] Rehearing Request by Williams.

[68] Rehearing Requests by Dynegy, Mirant, Reliant.

Services) has been eliminated by the SCAQMD's governing board and the rules governing generator run-times have been altered by the Governor of California. [69] There are 35 air quality districts within California and many of these districts treat NOx emissions differently from other air quality districts within California. Moreover, the ability of these districts and the state to change the rules governing NOx emissions renders a one size fits all approach for emission costs impractical.

However, mitigation fees associated with NOx emissions are a legitimate cost of producing energy. Therefore, generators should be permitted to recover the cost of these mitigation fees. We direct the ISO to develop a specific emission allowance administrative charge assessed against all in-state load served on the ISO's transmission system in order to recover NOx emission mitigation costs assessed against generators that are required to run in accordance with ISO dispatch instructions and the must offer provisions of this order. Monies collected through this administrative charge will be placed in an interest bearing escrow account by the ISO. When a generator actually incurs mitigation costs, the generator will submit an invoice to the ISO for recovery of these costs and the ISO must pay these invoices. Because all customers within California benefit from cleaner air as a result of application of these mitigation fees, the administrative charge should be assessed against all in-state load served on the ISO's system. We direct the ISO to submit tariff modifications incorporating an emission allowance administrative charge within fifteen days of the date of the order.

c. O&M Adder

The April 26 Order added $2.00 to the marginal cost price for each generator to represent operations and maintenance (O&M) expense. MID and the Assembly claim the Commission has not justified the $2.00 adder for O&M expenses. MID maintains the Commission should permit generators to include actual O&M costs.

Variable O&M costs are legitimate marginal costs that are incurred as a result of the physical production of energy. Therefore, an adder to the marginal price of energy is appropriate in order for the generating unit to recover its variable O&M costs associated with each MWh produced and bid into the ISO's imbalance energy market. The Commission found in San Diego Gas & Electric Company, et al., 94 FERC ¶ 61,245 (March 9 Order), that a $2/MWh adder for variable O&M expense was reasonable. Furthermore, in the March 9 Order, we noted that the California Energy Commission also estimates variable O&M expenses of $2 to $3/MWh in a recent report titled "Market Clearing Prices Under Alternative Resources Scenarios 2000 to 2010." [70]

We are cognizant of the concerns raised by MID that the O&M adder may be lower than actual O&M expenses; therefore, we will increase the O&M adder from $2/MWh to $6/MWh. The

[69] See Executive Order D-40-01 by the Governor of the State of California.

[70] 94 FERC at 61,863, n. 8.

O&M forecasts made by the California Energy Commission are for new, efficient combined cycle units that are not the units on the margin in the California market. An O&M adder of $6/MWh is based upon a seventeen year average of actual non-fuel O&M expenses for oil and gas-fired steam plants. [71] The California market primarily consists of older oil and gas-fired steam plants. Thus, using a long-term average of actual O&M expenses for the same kind of units currently in the California market should permit generators in the California market full recovery of all non-fuel expenses.

d. Heat Rate

The April 26 Order provided that the heat rate should be based on operational heat rates and should not include start-up and minimum fuel load costs. This requirement was justified because the market clearing price should reflect the costs needed to operate at or near maximum output. Williams maintains that the bid for each generator should include minimum fuel and start-up costs. It also maintains the price should be calculated each hour based on the heat rate and NOx curves for the point at which the unit is dispatched.

On May 18, 2001, the ISO submitted a status report informing the Commission that the ISO had issued two market notices to market participants providing a format for submission of the requested heat and emissions data. The ISO requested heat and emission rates for eleven different operating points with the first and last operating points representing the unit's minimum and maximum operating level, respectively. As noted by the ISO, by collecting eleven different operating points, the ISO will be able to approximate the actual incremental cost curve of each generating unit and thereby develop representative proxy prices for each unit throughout the unit's operating range.

The ISO's proposal to include the minimum and maximum operating levels for each unit and nine points in between is reasonable. The ISO's heat rate curve reflects the minimum fuel load requirements requested by Williams. In addition, because the ISO will have the approximate heat rate curve for each unit, the ISO is directed to calculate the proxy market clearing price based upon the approximate point on the heat rate curve at which the last unit is dispatched. [72] However, we will allow sellers to recover their actual start-up fuel costs. Sellers will invoice the ISO their actual start-up fuel costs for recovery by the ISO in the same manner that emissions costs are recovered, and the ISO must pay these invoices. We direct the ISO to submit tariff modifications incorporating these costs within 15 days of the date of this order. This change adequately reflects the concerns raised by Williams, and, therefore, its rehearing request is moot.

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[71] See http:/www.eia.doe.gov/oiaf/issues/opctbl3.html. Oil and Gas Steam Plant Operations and Maintenance Costs, 1981-1997.

[72] The emissions data is no longer relevant based upon our aforementioned removal of NOx costs from the proxy market clearing price.

e. Opportunity Cost, Scarcity Rents, Recovery of Fixed Costs, and Justification of Higher Prices

Generators maintain that the Commission's methodology for calculating marginal costs excludes legitimate opportunity costs related to energy-limited plants as well as scarcity rents.[73] They further maintain that paying only marginal cost of the last unit dispatched will not provide them with a reasonable opportunity to recover the fixed costs of peaking units. They further maintain that they will be unable to recover legitimate scarcity rents.

As discussed previously, the Commission is permitting generators to fully recover their emissions costs. As the Commission explained in the April 26 Order, in the real-time market, generators do not have opportunities to sell in higher-price markets because the real-time market consists only of energy that has not been previously sold in bilateral transactions. Since the Commission is imposing similar mitigation over the United States western markets in this order, sellers would no longer have any incentive to offer energy at a higher price to any other buyers in other states. Further, by using the marginal cost of the last unit dispatched to establish the market clearing price during periods of reserve deficiency, the Commission is permitting all more efficient generators a fair opportunity to recover capital costs.

The generators maintain that, while the market clearing price will enable generators more efficient than the last generator dispatched to recover capital costs, it will not permit recovery of the capital costs for that generator. Sellers such as Avista, Duke Energy, Dynegy, Reliant, and PPL have a portfolio of generating capacity, with units that will be more efficient than the unit setting the market clearing price. Therefore, the amounts earned on the more efficient plants will cover the investment in the marginal plant. Furthermore, we note that California no longer relies exclusively on the spot market. Negotiated bilateral agreements have, in large part, replaced this market and provide opportunity for any seller to structure the arrangements necessary to recover its costs. Finally, under the FPA and our authorization for market-based rates, sellers are not guaranteed to recover all costs but are provided the opportunity to do so.

The Commission, in this order, has sought to provide prices that emulate closely those that would result in a competitive market and that provide generators with a reasonable opportunity to recover their costs. Sellers have not suggested a reasonable method of measuring the magnitude of such costs. The Commission’s mitigation plan uses available data to develop a reasonable marginal cost for each generator and to permit reasonable recovery of legitimate costs. If sellers do not believe that these prices sufficiently cover their costs, they can file for cost-of-service rates covering all of their generating units in the WSCC for the duration of the mitigation plan.

[73] Rehearing Requests by Avista, Duke Energy, Dynegy, Reliant, PPL.

Reliant and PPL contend that generators are entitled to a premium to cover the real risk of non-payment in California. We recognize that the risk of nonpayment in California continues to be greater than that in the larger West-Wide market. We also note that there is a longer payment lag in the ISO spot markets of approximately 75 days that does not generally exist in the Western bilateral spot markets. We instruct the ISO to add 10 percent to the market clearing price paid to generators for all prospective sales in its markets to reflect credit uncertainty. [74] The adder is not instituted to compensate generators for past unpaid bills. The ISO must incorporate this provision in its compliance filing. This adder may be lifted by the Commission depending on the outcome of the settlement proceeding. However, the Commission believes that questionable business practices have sent negative signals to future supplies, credit rating agencies and investors and therefore an adder for credit risk is justified and necessary.

As described above, our order today prescribes a market-driven price mitigation mechanism in all hours. Sellers dissatisfied with these prices have two options. They may propose cost-based rates for their entire portfolio of generating facilities in the WSCC in a section 205 filing with cost support including a reasonable rate of return on investment that reflects the unique conditions in California. Alternatively, although we believe the mitigated price to be adequate, sellers can seek to justify each transaction above the mitigated price. Any such justifications, however, cannot include premiums to compensate for credit risk, since our market-clearing price for the ISO's markets already reflects an adder for this risk. Similarly, a seller's emission costs cannot be used to justify exceeding the market-clearing price because our order allows each seller to recover its emission costs directly from the ISO. Claims of opportunity costs will not be considered because energy that is available in real-time cannot be sold elsewhere. Also, as explained elsewhere, marketers will not be allowed to justify prices higher than the mitigated prices because they must be price takers. Finally, while our approach allows recovery of gas costs, we will consider justifications based on higher actual gas costs if conditions in natural gas markets change significantly (assuming, of course, that suppliers can document and support their gas purchasing portfolio and allocation among all generating units at the relevant time). [75]

3. Applicability to Marketers And Out-of-State Generators

A number of rehearing requests contend that generators can circumvent price mitigation by selling energy to marketers. [76] They argue the generator could sell energy to a marketer at a high price

[74] This adder will not be reflected in the market price for the rest of the WSCC.

[75] Currently, emission costs outside of California are de minimis. However, we recognize that this may change, and that sellers could be subject to entirely new costs resulting from changes in circumstances. We will consider such costs on a case-by-case basis.

[76] Rehearing Requests by ISO, CEOB CMUA, Metropolitan, NCPA, SMUD, San Diego,

and then the marketer could bid a high price into the ISO market, which it justified on the basis of its acquisition cost. In order to ensure compliance with the price mitigation, the Commission will not permit marketers to bid a price higher than the market clearing price. This will still provide marketers with an opportunity to earn a reasonable return on purchased energy, since the mitigated price is established by the marginal costs of the last unit dispatched and this price will be above the costs of the generators from which the marketers obtain their portfolio of energy. In this case, the marketer is no different than the last generator dispatched; it can recover the marginal costs of the last unit of energy produced.

The ISO maintains that out-of-state generators should be covered by the mitigation requirement so that any bids they submit above the market clearing price will be subject to refund. Out-of-state generators that want to have their marginal costs included in calculating the market clearing price can submit the required heat rate and gas source to the ISO for use in calculating the market clearing price. In the April 26 Order, the Commission did not require out-of-state generators to justify their price if they bid into the ISO market, because the Commission did not want to discourage out-of-state generators from bidding into the ISO market. However, now that the Commission is implementing mitigation for the entire WSCC, out-of-state generators will be treated like in-state generators.

F. Conditions on Market-Based Rate Authority

The April 26 Order conditioned public utility sellers' market-based rates to ensure that they do not engage in certain anticompetitive behavior. Sellers violating these conditions would have their market-based rates subject to refund and possible revocation.

Several generators have requested rehearing of this aspect of the April 26 Order.[77] Mirant and Williams, for example, urge the Commission to realize that sellers save certain units for when they can get the best price. Mirant contends that the bidding practices proscribed by the April 26 Order are legitimate, justifiable strategies in a competitive market and requests the Commission to eliminate the conditions or at a minimum, to limit the imposition of the conditions to certain hours.

Dynegy opposes the prohibition on the first category of bids, so-called "hockey stick" bidding. Dynegy submits that the risk of outage goes up substantially as the unit is pressed into operating longer than is advisable. The generator, therefore, faces new risks, such as a forced outage, and must be able to place premiums on the price per unit. EPSA, meanwhile, opposes the prohibition on bids that rise as the unit's output drops. EPSA states that the Commission should not revoke market-based rate authority based on a legitimate effort to recover total costs, but rather only if it finds that market power has been abused.

[76](...continued)
Edison.

[77]Rehearing Requests by Dynegy, Mirant, Reliant, EPSA, Duke, PPL.

We will not tolerate abuse of market power or anticompetitive bidding or behavior. Emblematic of these practices is the now well-publicized bid of $3,880/MWh by Duke Energy. This bid resulted in total revenues for Duke Energy of $11 million. Exacerbating the problem was the fact that, while this transaction was identified in the March 9 Order as exceeding the proxy price, Duke Energy failed to even report this transaction in its quarterly report. The March 9 Order gave Duke Energy the choice of refunding all revenues in excess of those that would have occurred using the proxy price, or justifying the higher bid. Duke Energy chose the latter. Duke Energy argued that the payments for the energy it had supplied were in arrears, and therefore, it added a credit premium. The data show that Duke Energy's risk premium exceeds its variable cost by an order of magnitude. [78] Duke Energy's bidding at multiples of its marginal costs in an attempt to recover past due amounts can in no way be found to be just and reasonable. Accordingly, Duke Energy is directed to refund with interest pursuant to 18 C.F.R. § 35.19a, or offset, down to the level of the proxy price, $273/MWh for January, during the relevant hours. As the proxy price is well above Duke Energy's claimed running costs, it will be sufficient to cover any credit risk that Duke Energy may face. [79]

Public utility sellers' market based rate authority will be subject to potential revocation if they are found to have engaged in inappropriate behavior. Further, WSCC public utility sellers' market-based rate authorizations are hereby conditioned on agreeing to potential refunds for overcharges resulting from anticompetitive behavior.

The Commission denies Dynegy's request asking the Commission to clarify that the prohibition on bidding practices will expire on April 30, 2002, along with the rest of the April 26 Order.

G. Refunds

In the April 26 Order, the Commission established that all charges below the market clearing price would not be subject to refund. Refunds would be required only for sellers that fail to justify bids above the market clearing price. The Commission further stated that generators would not be liable for refunds if the Commission did not act within 60 days of the filing of the justification report.

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[78] Duke Energy unequivocally states that it is using the $3,880/MWh bid as a negotiating tool to recover payment for prior transactions. Duke Energy states that it will settle for the proxy price if and when it is paid in full for its prior, unpaid transactions. March 23, 2001 compliance filing in Docket Nos. ER01-1448-003 and ER01-1448-004 at pp. 10-12.

[79] The Commission notes that there are a number of submittals dealing with sellers' market-based rate authorizations as well as bid justifications. We will address them in separate orders, if not resolved as part of the settlement process established elsewhere in this order.

PG&E and Edison maintain that the Commission cannot erase statutory refund obligations by stating that certain prices are deemed just and reasonable. Edison argues that the Commission must order refunds for all amounts above a just and reasonable rate and should not be able to limit refunds to emergency situations. Edison maintains that the Commission cannot establish that refund authority will expire within 60 days. It further contends that the Commission cannot shield generators from refunds, because the Commission has the authority to correct its legal errors. The CPUC maintains that refunds should exceed unlawful gains to act as a deterrent and suggests that the Commission impose treble damages, as provided for in antitrust law.

The Commission is establishing price mitigation in all hours of reserve deficiency and, as a discretionary matter, is also extending a form of that mitigation to hours of non-reserve deficiency. This price mitigation establishes the maximum just and reasonable rates in spot markets, absent cost justification. Moreover, the 60 day period for review of cost justifications was a self-imposed requirement to ensure that there is price certainty. The Commission has the authority to extend the period if necessary to finish processing the justifications.

With respect to the CPUC's arguments, the CPUC cites no provision of the FPA authorizing the Commission to impose penalties. Finally, the Commission has no authority to impose treble damages.

H. Underscheduling Penalty

On December 15, 2000, the Commission issued an order which established, among other things, as part of a comprehensive price mitigation plan, a maximum penalty of $100/MWh if energy buyers had over 5 percent of their load served in the real-time market. [80] Several parties request that the Commission suspend the penalty for underscheduling in this proceeding. [81] Due to the Commission's decision in the April 26 Order to defer action on suspending the penalty for underscheduling, we will address this issue in a future order.

I. Confidentiality of Data

The Commission stated in the April 26 Order that it would continue the previous practice of keeping bid data confidential for six months, because 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. The Commission also found that generator's heat rates and emission cost information was also confidential business information that should not be disclosed.

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

[81] See Comments by CPUC, DWR, PG&E.

Several parties contend that the Commission should not keep the heat rate and other cost information used to justify bids confidential, but should make the data publicly available, under section 205 of the FPA, on a next-day basis. [82] They also assert that due process requires that all data used to determine the proxy price is an essential part of a rate schedule and must be made available so it can be challenged by other parties, particularly ratepayers. SCWC and Assembly contend that the solution to collusion or gaming is not confidentiality, but rather regulation of seller conduct. As an alternative, San Francisco and Assembly maintain that the Commission can keep the data confidential, but that the filing of the data should be publicly noticed pursuant to the FPA, and the data should be available for review by those parties who enter into a protective order.

As the Commission found in the April 26 Order, the information on heat rates and emission costs is highly confidential business information. The disclosure of such information can cause competitive harm by allowing competitors to learn of the behavior and costs of their competitors. The Commission regulations provide for granting confidential treatment of business sensitive information. [83] These issues are raised in other pleadings before the Commission, and we will address these matters in a later order.

EPSA's concerns relate to the independence of the ISO Board and the apprehension of disclosing confidential data to a non-independent body. EPSA suggests replacing the ISO Board or alternatively, requiring the reporting of such data to an independent entity so it can perform the marginal cost calculations. The concerns related to the independence of the ISO Board are beyond the scope of this rehearing and will be addressed in a later order.

M-S-R and TANC state that the April 26 Order is silent with respect to ordering the ISO to keep the bid and cost data confidential. While the Commission finds that the order was sufficiently clear in the first instance, out of an abundance of caution, the Commission clarifies that the ISO is ordered to treat all cost data in a confidential manner.

J. Review and Duration of the Mitigation Plan

In the April 26 Order, the Commission established a maximum one-year time period for the duration of the mitigation plan. In addition, the Commission instituted a process for reviewing the operations of the plan and the conditions in the California market on a quarterly basis.

Several parties request rehearing on the duration of the mitigation plan, stating that the Commission's decision to establish a pre-determined time period for applying mitigation is arbitrary and

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[82] Rehearing Requests by NCPA, Assembly, SCWC, Edison, San Francisco, PG&E.

[83] See 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).

capricious.[84] Anaheim asserts that there is no rational basis for ending the mitigation after one year while SCWC states that the only criterion for terminating mitigation is whether markets are competitive or not. Metropolitan states that the Commission's assumptions about planned demand reduction and market development within one year should not be the basis for terminating mitigation. Metropolitan, Assembly, and others urge the Commission to monitor the progress of market entry by new generation and other market developments before termination.

The Commission is requiring the ISO to file on or before March 26, 2002, a report on market conditions that addresses among other things: (1) a list of all new generating resources (including the nameplate capacity) that the State of California has announced this year would be on line by summer 2002 and which of those facilities actually are on line (see Attachment to this order); [85] and (2) the continued progress in executing long-term contracts and reducing the reliance on the spot market. We will extend the mitigation through September 30, 2002. Our requirement for quarterly reports will continue.

K. RTO Proposal

In the April 26 Order, the Commission conditioned the implementation of the market monitoring and mitigation plan on the ISO and the three investor-owned utilities (IOUs) (SDG&E, Edison, and PG&E) filing an RTO proposal by June 1, 2001, consistent with the characteristics and functions in Order No. 2000.

Several parties have requested rehearing challenging the Commission's conditioning mitigation on the filing of an RTO. [86] While requesting rehearing on the lawfulness of the condition, City of Seattle and others assert that filing an RTO proposal by June 1, 2001 is highly unrealistic, and therefore request that the RTO condition be removed from the April 26 Order on rehearing.

As noted in the April 26 Order, the RTO condition recognizes that the only real solution to supply problems that affect the Western United States is to create a regional response. The Commission intended to create such a response, and to improve and enhance supply and deliverability infrastructure so as to make the deliverability of supply possible and more reliable by imposing this condition as a necessary component to a solution for California and the Western United States. The

[84] Rehearing Requests by Edison, CPUC, CMUA, Anaheim, SCWC, Metropolitan.

[85] As pointed out in the April 26 Order, California has committed itself to increasing in-state generation and projects that new generation totaling 4,168 MW will be on line by the end of August 2001 and that there could be as much as 6,879 MW on line for the summer of 2002.

[86] Rehearing Requests by Seattle, Anaheim, SCWC, San Diego, CPUC, PG&E, CMUA, Metropolitan, CEOB.

ISO and two IOUs, SDG&E and Edison, filed an RTO proposal on June 1, 2001. PG&E also made a separate filing. Since the RTO filings have been made, the monitoring and mitigation plan will remain in effect. The Commission will address the adequacy of these filings in future orders. Since the ISO and utilities made the requisite filings, the requests for rehearing on this issue are moot.

L. West-Wide 206 Implementation

In the April 26 Order, the Commission instituted an investigation under section 206 of the FPA into the rates, terms and conditions of sales for resale of electric energy in interstate commerce in the WSCC other than sales through the ISO's 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. These proceedings were instituted to investigate whether and the extent to which significant increases in the prices for energy and ancillary services in the California market are affecting prices for such services in the WSCC outside of California.

In the April 26 Order, the Commission recognized that the California market is integrated with those of other states in the WSCC. Therefore, the Commission stated its intention that, to the extent possible, its proposed changes would mirror the measures to be applied to California markets. [87] The April 26 Order proposed the following three measures for the WSCC:

(1) A requirement that all public and non-public utility sellers, with energy operationally and contractually available in real-time, offer that energy for sale;

(2) Price mitigation during periods when reserves fall below 7 percent; and

(3) A condition on the market based rate authority of public utility sellers selling in the WSCC region to ensure that they do not engage in anti-competitive behavior.

On April 27, 2001, the Commission issued a notice establishing a refund effective date 60 days from the date on which notice of initiation of the investigation was published in the Federal Register. The notice was published in the Federal Register, 66 Fed. Reg. 22223, on May 3, 2001. Thus, the refund effective date is July 2, 2001.

1. WSCC Mitigation Plan Overview

Based upon the need for uniform pricing throughout the Western region, we now find it necessary to adopt a market monitoring and mitigation plan for the WSCC spot markets. This plan will

[87] 95 FERC ¶ 61,115, at 61,356.

consist of several primary elements, each of which is intended to closely mirror the monitoring and mitigation plan we have adopted for California while also taking into account the various disparities between the California and WSCC markets.

Effective on the day following the date of this order, the plan we adopt below applies in all hours to all spot market transactions throughout the WSCC. In the hours when California experiences reserve deficiencies, prices for WSCC spot market sales cannot exceed the ISO's hourly market clearing price, absent justification.

Under our current and revised mitigation plan, the price in the ISO's Imbalance Market during times of insufficient operating reserves will consistently reflect the marginal cost of energy. Recent data show that during hours of sufficient operating reserves, the average hourly Imbalance Energy price has been zero and at times a negative value. These prices indicate that either there were no transactions in this market or that generation actually exceeded load during these hours. While there may be a number of factors that contribute to these anomalous results (e.g. changes in buying strategies), we are convinced that we must use a modified mitigation approach during hours of non-reserve deficiencies.

For spot market sales, both in the WSCC and in California, in all non- reserve deficiency hours (i.e., when reserve levels in the ISO exceed 7%), we will adapt the use of these market clearing prices. Eighty-five percent (85%) of the highest ISO hourly market clearing price established during the hours when the last Stage 1 (not Stage 2 or 3) was in effect will, absent justification, serve as the maximum price for the subsequent period. For example, if the highest hourly market clearing price during a Stage 1 is $140/MWh, spot prices in all subsequent non-reserve deficiency hours beginning when Stage 1 is lifted can be no higher than $119/MWh (i.e. 85 percent of $140/MWh). Sellers through the ISO's single price auction will receive the hourly market clearing price, but that clearing price will not exceed $119/MWh. For example, if the market clears at $90/MWh all bidders in the ISO's auctions will receive $90/MWh for that hour. However, bids are limited to $119/MWh and, therefore, the clearing price during the period will never exceed $119/MWh. For sales outside the ISO's single price auctions (bilateral sales in California and the rest of the WSCC), sellers will receive the prices they negotiate up to the maximum price, in this example, up to $119/MWh. This maximum clearing price will remain in place until the next Stage 1 is declared and a new price is set. When that Stage 1 is lifted, 85% of the highest hourly market clearing price from that period will carry forward.

Third, the plan imposes a must-offer requirement for all hours upon sellers with the exception of hydroelectric resources and capacity needed to meet WSCC minimum operating reserve criteria for control areas. Fourth, the plan applies to all public utilities (including marketers) and non-public utilities who sell into Commission-regulated spot markets or use the interstate transmission grid subject to our jurisdiction. Market-based rate authorizations for public utilities are hereby conditioned upon adherence to this plan.

2. Interventions and Comments

In the April 26 Order, the Commission provided that comments should be submitted within ten days of the date of that order. Timely notices of intervention, motions to intervene and comments in the WSCC proceeding were filed by the entities listed in Appendix B.

Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, notices of intervention and timely, unopposed motions to intervene serve to make the intervenors listed in Appendix B parties to this proceeding. Given the early stage of the proceedings, we will accept the late-filed comments.

3. Megawatt Laundering

In the April 26 Order, the Commission noted that several commenters complained that generators may avoid the Commission's mitigation requirements through "megawatt laundering." In that order, the Commission recognized that the California market is integrated with other states and instituted the instant investigation. In addition, the Commission extended the must-offer obligation to include non-public utility generators in California which currently make use of the ISO's interstate transmission grid. In their comments, CPUC, DWR, TURN/UCAN, and CEOB request that the Commission also address megawatt laundering in this proceeding.

As discussed above, megawatt laundering will no longer be a concern due to our revised mitigation plan. First, the mitigation plan will be for all hours and will be applicable uniformly throughout the WSCC. Second, both sales within and outside California will be treated uniformly including sales by marketers. As a result of these modifications, this strategy cannot be used to avoid potential mitigation.

4. The Proposed 7 Percent Reserve Deficiency Trigger

The April 26 Order established 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, and proposed that mitigation in the WSCC would be triggered when contingency reserves (as defined by the WSCC) for any control area fall below 7 percent.

Numerous commenters raise issues regarding how the reserve deficiency mechanism would be implemented for the WSCC. Based on the numerous concerns raised by the comments, we will simplify the West-wide mitigation so that it will trigger only when the ISO declares a reserve deficiency.

5. The Proposed Must-Offer Requirement

In the April 26 Order, the Commission included a requirement that all generators in California (with the exception of hydroelectric power), including non-public utility generators that make sales through the ISO's markets or that use the ISO's interstate transmission grid, must offer any power that they have available in real time to the ISO. This includes power not already scheduled to run through bilateral agreements.[88] With respect to the WSCC investigation, the Commission stated that it intends to mirror the approach used in California.

A number of parties oppose the requirement for the WSCC. For example, the Oregon Office of Energy believes that a requirement to offer energy for sale is difficult to police because a generator must be allowed to decide when its equipment must be taken out of service and at what levels of output it can run.

We clarify that the must offer requirement throughout the WSCC will not apply to hydroelectric resources or to generation that is necessary for control area operators to meet the applicable WSCC Minimum Operating Reserve Criteria. We recognize that outside of California there is currently no operational ISO or RTO in place in the WSCC and therefore, no centralized location to post this information. The lack of an operational regional structure will make implementation of this feature of the mitigation plan difficult.

In order to implement this feature of the mitigation plan immediately, we will require all public utilities that are control area operators to have their wholesale merchant function calculate on a daily basis the amount of capacity that will be available after load and operating reserve forecasts have been calculated. The wholesale merchant function will post this information on its company web site and on the Western System Power Pool (WSPP) web site, and will maintain in its daily log the amount of non-hydro resources that will be available. Actual arrangements for energy sales from such resources should be made with the wholesale merchant function and not with the control area operator.

To implement this requirement, we will require each marketer and independent power producing entity to post available capacity on a daily basis on its own web site and the WSPP web site.

6. Applicability to Non-public Utilities

The April 26 Order extended the must-offer requirement and the price mitigation plan to non-public utility generators in California which currently make use of the ISO's interstate transmission grid or sell in the ISO's markets. The Commission found that extending these requirements to non-public utilities is necessary to ensure that the mitigation and monitoring proposal is applied equally to all

[88] 95 FERC ¶ 61,115, at 61,355-57.

generators in California. [89] Similarly, the April 26 Order proposes to extend these requirements to non-public utility generators in the WSCC. [90]

Non-public utilities oppose applying these requirements to them. On the other hand, Avista Energy requests that the Commission suspend price mitigation measures established for public utilities in the WSCC if the Commission does not extend the mitigation measures to non-public utility sellers.

For the same reasons the April 26 Order applied mitigation to all generators within California, we will extend the mitigation plan adopted herein to include all public and non-public utilities throughout the WSCC. Moreover, the percentage of non-public utility generation in the WSCC outside of California is significantly larger than that inside of California.[91] We believe that all entities must assist with solving the problems in the WSCC. Accordingly, the Commission will require that, as a condition of selling into the markets which are subject to this Commission's exclusive jurisdiction, and as a condition of using Commission jurisdictional interstate transmission facilities, all sellers located in the WSCC, including non-public utility sellers in the WSCC, must abide by the WSCC price mitigation plan and by the must-offer obligation (if applicable) described in this order.

While the Commission does not directly regulate the non-public utility sales for resale throughout the WSCC, we have the authority, and, indeed, the responsibility, to ensure that rates, terms and conditions for jurisdictional service are just and reasonable. However, the Commission cannot ensure such just and reasonable rates in the current circumstances in the WSCC unless all entities that sell energy in the relevant spot markets or use the interstate transmission grid subject to our jurisdiction abide by the same conditions. Finally, by applying the plan discussed in this order to non-public utilities, we eliminate the incentive, and the means, for public utilities to avoid mitigation (i.e., by making wholesale sales to non-public utilities for resale in the spot market).

7. Refund Issues

As noted above, the refund effective date established in this proceeding is July 2, 2001. Some parties contend that it is premature to establish a refund effective date for the WSCC, or that the prospect of refunds could cloud supplier decision-making, while others are concerned that if a

[89] Id. at 61,356 .

[90] Id. at 61,365.

[91] See Powerdat database, Resource Data International, Inc., April 2001 data set.

transaction is executed in the day-ahead market prior to a declared reserve deficiency, the transaction should be honored without mitigation or refund obligation. [92]

We will not rescind the refund effective date because we are legally obligated to establish a refund effective date when an investigation is instituted under section 206 of the FPA. We have established the earliest possible refund effective date permitted by the FPA Section 206, to provide maximum protection to customers. We expect that sellers will observe the requirements of this order and that the need for refunds will be rare. The commenters have not justified providing less protection. Moreover, the mitigation plan is taking effect prior to the refund effective date and this should obviate the need for refunds.

8. Mitigation Beyond Summer 2001

Although we are confident of the efficacy of our West-wide mitigation plan throughout the Summer of 2001, we nonetheless wish to obtain comment for the purpose of revising the mitigation methodology for future periods, if necessary. [93] Accordingly, we invite interested partes to file with the Commission comments and proposals concerning: (1) any developments, either beneficial or adverse, which have occurred in the Western region spot markets as a result of this order; (2) any difficulties with implementation of the mitigation plan detailed in the order, and the relevant solutions thereto; and, most importantly (3) any alternative market mitigation approaches. In order to provide for timely review and analysis, we will require that parties' comments and proposals be submitted to the Commission within 60 days of the date of issuance of this order.

M. Settlement Conference

We will require that all public utility sellers and buyers in the ISO's markets participate in settlement discussions to complete the task of settling past accounts and structuring the new arrangements for California's energy future. To achieve this goal, it is imperative that the parties reach agreement on (1) the additional load that is to be moved from the spot market to longer-term contracts, (2) refund (offset) issues related to past periods, and (3) creditworthiness matters. In highlighting these specific issues, we are not suggesting that the settlement discussions are limited to these matters, but emphasize that all issues that remain outstanding to resolve past accounts and ensure California's energy future are on the table for the parties to address. Finally, we stress that it will be critical to the success of these discussions that the State of California designate one or more representatives, authorized to act on behalf of all affected state interests, to participate fully in the settlement discussions. We will appoint the Chief Administrative Law Judge or his designee to serve as

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[92] See Comments of Avista Energy, Duke and Powerex.

[93] In particular, we seek comments on whether our approach is appropriate given regional differences between California and other regions.

a settlement judge to assist the parties in reaching a settlement and require the judge to convene an initial settlement conference no later than June 25, 2001, and to complete the settlement discussions no later than 15 days after the commencement of the settlement conference. The settlement judge shall make a recommendation to the Commission within 7 days after the close of the settlement discussions if the issues are not resolved by the parties.

N. ISO Compliance Filing

In the April 26 Order, the Commission directed the ISO to submit a compliance filing no later than fifteen days from the date of that order. The ISO made its compliance filing in Docket Nos. EL00-95-034 and EL00-98-033 on May 11, 2001. Due to the significant modifications to the mitigation plan we are adopting today, we will require a new compliance filing within 15 days of the date of this order.

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) Sellers of energy in the WSCC are subject to the mitigation plan as discussed in the body of this order. The mitigation plan will become effective on the day following the date of this order.

(C) Rehearing is granted in part, and denied in part, as discussed in the body of this order.

(D) The requests for stays of the April 26 Order are denied as discussed in the body of the order.

(E) No later than 7 days after the completion of settlement discussions, the settlement judge shall make a recommendation to the Commission with respect to the settlement negotiations in the captioned dockets.

(F) Duke Energy must file a report quantifying refunds or offsets within 15 days of the date of this order, as discussed in the body of this order.

(G) Interested parties are hereby invited to file comments and proposals regarding the market mitigation plan, as discussed in the body of this order.

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

(S E A L) Commissioner Breathitt concurred with a separate statement attached.

Linwood A. Watson, Jr.,
Acting Secretary.

Appendix A
Requests for Rehearing of April 26 Order
(* - denotes request for late intervention)

Party	Abbreviation
American Public Power Association	APPA
Automated Power Exchange	APX
Avista Energy, Inc.	Avista Energy
California Air Resources Board *	ARB
California Department of Water Resources	DWR
California Electricity Oversight Board	CEOB
California Independent System Operator Corporation	ISO
California Municipal Utility Association	CMUA
California State Assembly	Assembly
Calpine Corporation	Calpine
Cities of Anaheim, et al.	Anaheim
City and County of San Francisco	San Francisco
City of Burbank *	Burbank
City of San Diego	San Diego
City of Seattle	Seattle
Cogeneration Association of California and Energy Producers and Users Coalition [94]	CAC/EPUC
Consumer Federation of America *	CFA
Duke Energy North America, et al., LLC	Duke Energy
Dynegy Power Marketing, Inc. et al.	Dynegy

[94] Request for stay.

Party	Abbreviation
Electric Power Supply Association	EPSA
Imperial Irrigation District *	IID
Los Angeles Department of Water and Power	LADWP
M-S-R Public Power Agency, et al.	M-S-R
Metropolitan Water District of Southern California	Metropolitan
Mirant America's Energy Marketing, LP, et al.	Mirant
Modesto Irrigation District	MID
National Rural Electric Cooperative Association *	NRECA
Northern California Power Agency	NCPA
Pacific Gas and Electric Company	PG&E
PPL EnergyPlus, LLC, et al.	PPL
Public Utilities Commission of State of California	CPUC
Reliant Energy Power Generation, Inc.	Reliant
Sacramento Municipal Utility District	SMUD
San Diego Gas & Electric Co.	SDG&E
South Coast Air Quality Management District *	SCAQMD
Southern California Edison Company	Edison
Southern California Water Company	SCWC
Transmission Agency of Northern California	TANC
Turlock Irrigation District *	TID
Williams Energy Marketing & Trading Company	Williams

Appendix B
WSCC Comments
(* - denotes Motions to Intervene)
(** - denotes Notice of Intervention)
(*** - denotes late filed comments)

Party	Abbreviation
AES Southland, Inc. ***	AES
American Public Power Association *	APPA
Attorney General of Washington *	Washington Attorney General
Automated Power Exchange	APX
Avista Energy, Inc.	Avista Energy
Avista Utilities	Avista Utilities
California Air Resources Board *	ARB
California Department of Water Resources *	DWR
California Electricity Oversight Board ***	CEOB
California Independent System Operator Corporation	ISO
California Municipal Utility Association	CMUA
California State Assembly	Assembly
Cities of Anaheim, et al. *	Anaheim
County of San Diego *	San Diego
City and County of San Francisco *	San Francisco
City of Burbank *	Burbank
City of Seattle	Seattle
Cogeneration Association of California and Energy Producers and Users Coalition *	CAC/EPUC
Cogeneration Coalition of Washington *	CCW

Party	Abbreviation
Colorado Association of Municipal Utilities *	Colorado AMPS
Duke Energy North America, et al., LLC *	Duke Energy
Electric Power Supply Association	EPSA
Enron Power Marketing , Inc. and Coral Power, L.L.C.	Enron
Idaho Public Utilities Commission **	Idaho Commission
Imperial Irrigation District *	IID
Los Angeles Department of Water and Power ***	LADWP
M-S-R Public Power Agency, et al.	M-S-R
Metropolitan Water District of Southern California	Metropolitan
Mirant America's Energy Marketing, LP, et al. *	Mirant
Modesto Irrigation District *	MID
Morgan Stanley Capital Group Inc.	Morgan Stanley
National Rural Electric Cooperative Association*	NRECA
Nevada Attorney General's Bureau of Consumer Protection *	Nevada BCP
Nevada Independent Energy Coalition*	NIEC
Nevada Public Utilities Commission *	Nevada Commission
Northern California Power Agency	NCPA
NRG Power Marketing Inc.	NRG
Official Committee of Unsecured Creditors of PG&E *	OSC
Oregon Office of Energy	Oregon Office of Energy
Pacific Gas and Electric Company *	PG&E

Party	Abbreviation
Pinnacle West Capital Corporation, Arizona Public Service Company, Pinnacle West Energy Corporation and APS Energy Services, Inc.	Pinnacle West Companies
Portland General Electric Company	PGE
Powerex Corporation *	Powerex
PPL EnergyPlus, LLC, et al. *	PPL
Public Utilities Commission of State of California **	CPUC
Puget Sound Energy, Inc.*	Puget Sound
Reliant Energy Power Generation, Inc.	Reliant
Sacramento Municipal Utility District	SMUD
Salt River Project Agricultural Improvement and Power District *	SRP
San Diego Gas & Electric Co. * ***	SDG&E
South Coast Air Quality Management District *	SCAQMD
Southern California Edison Company *	Edison
Tri-State Generation and Transmission Association, Inc. *	Tri-State
Turlock Irrigation District *	Turlock
Utah Municipal Power Agency *	UMPA
Utility Reform Network and the Utility Consumers' Action Network	TURN/UCAN
Washington Utilities and Transportation Commission **	Washington Commission
Williams Energy Marketing &Trading Company	Williams
Wyoming Public Service Commission ***	Wyoming Commission

PRESS RELEASE NOT ON DISKETTE

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company
Complainant,

v. Docket No. EL00-95-031

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. EL00-98-030, EL00-98-033

California Independent System Operator Corporation — Docket No. RT01-85-000, RT01-85-001

Investigation of Wholesale Rates of Public Utility Sellers of Energy and Ancillary Services in the Western System Coordinating Council — Docket No. EL01-68-000, EL01-68-001

(Issued June 19, 2001)

MASSEY, Commissioner, concurring in part:

Today's order brings expanded price restraints mitigation to a broken market. I support the order because it adopts measures that I have been championing for the past eight months. Price controls are now extended to the entire western interconnection, thereby eliminating the "megawatt laundering" problem that has vexed the mitigation programs adopted by the Commission and the ISO over the past year. Cost-based price constraints are now extended to all hours, not just those of reserve deficiency. We have long needed 24 x 7 coverage, and now we finally have it. The price caps will remain in place until September 2002, giving the market two full summers to correct. I endorse these measures.

While better late than never, I wish this Commission had taken effective action sooner. Until today, the Commission had stubbornly refused to implement full time price constraints, despite rather clear evidence that prices were not just and reasonable. We could have prevented much of the economic carnage in the western interconnection that has occurred over the past year.

Given that the Commission today adopts measures that I have long advocated, I am tempted to declare victory and let it be. But I cannot. There are some aspects of the order that I have reservations about, and for these reasons I concur with the order. One aspect is the addition of a 10 percent surcharge to the market clearing price to reflect credit uncertainty. I do not see the need for this. The Commission has issued orders in the past few months instructing the ISO to abide by the creditworthiness requirements of its tariff. I am concerned that the adder may diminish the ISO's enforcement of those requirements. Moreover, it is my understanding that recently all sales into the ISO's markets have been backed by a creditworthy party. Instituting this surcharge does have a modest bright side, however. Generators may no longer attempt to justify bids on the basis of credit risk above what is provided for in the cost based clearing pricing methodology. This was a major flaw of the old ineffective $150 benchmark in our earlier mitigation program. Eliminating that ground for high prices is a positive development.

Second, the order should have provided guidance to the parties that will participate in the settlement conference we order. I believe we are avoiding our responsibility under the Federal Power Act to set just and reasonable prices by requiring parties to settle a multitude of issues with a price tag in the billions of dollars without at least two cents worth of guidance.

And finally, I do not agree with the rhetoric in this order that characterizes cost of service pricing as irrelevant, and perhaps even downright harmful, on the theory that it would discourage new supply. I do not understand the need nor the logic of this language. We have made a choice in this order to strike a balance between strict cost of service regulation and blind reliance on the market. The mitigation program puts in place important cost based price caps while relying on market based pricing. The order sets out reasons for this balanced choice, and articulating them is all that is needed to support our decision. I strongly disagree with the statement in the order that "a cost-based inquiry alone would not be sufficient in these circumstances to fulfill the statutory duty" under the Federal Power Act. I do not read the Federal Power Act, and the relevant court decisions, so restrictively. There is still an important role for cost of service regulation where markets are not adequate.

What is curious about this aspect of the order is that the concern is to avoid discouraging new supply. However, as the well respected economist Alfred Kahn recently said of our long reliance on cost of service regulation, "(i)f the literature agrees on anything about that experience, it is that cost-based regulation, as traditionally practiced, has encouraged the goldplating of service and the very excess capacity that seemed to promise such enormous benefits to consumers during the past decade if rates were deregulated."[1] Dr. Kahn believes that cost of service may lead to too much supply. Thus, I do not understand the majority's logic concerning cost-based regulation and supply adequacy.

These concerns notwithstanding, I support today's order and the price protection plan it puts in place. To ensure that this price protection plan is successful, the Commission must exercise all of its statutory powers to keep natural gas prices in the West at just and reasonable levels. It is probably generally true that the marginal plant dispatched in California is fired by natural gas and uses a lot of it. Thus, the success of the plan we adopt today in lowering prices depends in large part on fluctuations in the price of natural gas. The Commission continues to have work to do in ensuring just and reasonable gas prices.

Today's price protection plan gives California and the West breathing room while their electricity markets are brought back to health. A number of items need to be addressed in the next 15 months for the recuperation to be successful. Clearly, there must be substantial amounts of new generation capacity brought on line. A more balanced supply portfolio must be developed as California moves away from an over reliance on the spot markets. A robust demand response program must be implemented through demand bidding and accurate price signals. Transmission constraints must be relieved in some way. And finally, the California ISO should explore a number of market reforms, such as the adoption of security constrained unit commitment dispatch, the creation of an installed capacity market and reserve requirements, and a single integrated day-ahead market. Without these measures, I would be concerned about whether the markets in the West can be brought back to health.

For these reasons, I concur with today's order.

William L. Massey
Commissioner

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company,

v. Docket No. EL00-95-031

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

[1] Statement of Alfred E. Kahn before the Committee on Governmental Affairs, United States Senate, June 13, 2001 at page 3.

Investigation of Practices of the California Independent System Operator and the California Power Exchange | Docket Nos. EL00-98-030, EL00-98-033

California Independent System Operator Corporation | Docket Nos. RT01-85-000, RT01-85-001

Investigation of Wholesale Rates of Public Utility Sellers of Energy and Ancillary Services in the Western Systems Coordinating Council | Docket Nos. EL01-68-000, EL01-68-001

(Issued June 19, 2001)

Breathitt, Commissioner, concurring;

I concur with the result of today's order, and write separately to highlight one aspect of it. I am concerned about the imposition of a ten percent surcharge on the market clearing price paid to generators to reflect credit uncertainty in California. I have two primary concerns. First, the imposition of such a credit surcharge seems to concede to the California Independent System Operator (ISO) the issue of whether or not the ISO must implement the Commission's creditworthiness standards. We have directed the ISO to ensure the presence of a creditworthy counterparty for certain transactions.[1] I am not

ready to concede this issue and, therefore, I call upon the ISO immediately to implement our orders regarding creditworthiness.

Second, I believe the imposition of such a credit surcharge may be premature. In today's order we also initiate settlement discussions among all public utility sellers and buyers in the ISO markets. Among the issues we direct the parties to consider in their negotiations are "creditworthiness matters." I am concerned that the credit surcharge could adversely affect the settlement discussions on the issue of prospective credit uncertainty.

[1] California Independent System Operator Corporation, et al., 95 FERC ¶ 61,026, at 61,081 (2001)

Otherwise, I agree with my colleagues that creditworthiness and non-payment of accounts are serious problems in California. I believe the Commission and the ISO must take immeditate steps to address these problems. I just hope this surcharge does not prove to be an inappropriate remedy for this problem. Therefore, I respectfully concur.

Linda K. Breathitt
Commissioner