93 FERC ¶ 61,294

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company, Complainant, v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange, Respondents.	Docket Nos. EL00-95-000 EL00-95-002 EL00-95-003
Investigation of Practices of the California Independent System Operator and the California Power Exchange	Docket Nos. EL00-98-000 EL00-98-002 EL00-98-003
Public Meeting in San Diego, California	Docket No. EL00-107-000
Reliant Energy Power Generation, Inc., Dynegy Power Marketing, Inc., and Southern Energy California, L.L.C., Complainants, v. California Independent System Operator Corporation, Respondent.	Docket No. EL00-97-000
California Electricity Oversight Board, Complainant, v. All Sellers of Energy and Ancillary Services Into the Energy and Ancillary Services Markets Operated by the California Independent System Operator and the California Power Exchange, Respondents.	Docket No. EL00-104-000

Docket No. EL00-95-000, et al.

California Municipal Utilities Association,
Complainant,
v.
All Jurisdictional Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange,
Respondents.

Docket No. EL01-1-000

Californians for Renewable Energy, Inc. (CARE),
Complainant,
v.
Independent Energy Producers, Inc., and All Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange; All Scheduling Coordinators Acting on Behalf of the Above Sellers; California Independent System Operator Corporation; and California Power Exchange Corporation,
Respondents.

Docket No. EL01-2-000

Puget Sound Energy, Inc.,
Complainant,
v.
All Jurisdictional Sellers of Energy and/or Capacity at Wholesale Into Electric Energy and/or Capacity Markets in the Pacific Northwest, Including Parties to the Western Systems Power Pool Agreement,
Respondents.

Docket No. EL01-10-000

ORDER DIRECTING REMEDIES FOR CALIFORNIA WHOLESALE ELECTRIC MARKETS

Issued: December 15, 2000

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Introduction and Summary

On November 1, 2000, the Commission issued in the above dockets an order proposing specific remedies to address dysfunctions in California's wholesale bulk power markets and to ensure just and reasonable wholesale power rates by public utility sellers in California. The electric power situation in California has worsened since our November 1 order was issued and it is critical that both we and California State regulators take immediate steps within our respective jurisdictions to correct the situation. Today, in the interest of protecting consumers, ensuring creditworthiness of market participants, and moving the Western markets toward the kind of rules that will sustain the electric industry in the long run, we adopt and direct specific remedies within our authority under the Federal Power Act. These remedies are designed to help alleviate the extreme high prices being borne by Californians, but also to ensure that sellers continue to have incentives to sell into California and sufficient incentives to build sorely needed new generation and transmission necessary to provide reliable service in the future. However, as discussed further herein, the problems facing consumers in California cannot be alleviated unless the State also takes immediate steps to remove restrictions, identified below, that it has imposed on the three investor-owned suppliers in California and to permit needed infrastructure.

Beginning in 1996, this Commission issued a series of orders which, at the urging of California State regulators, deferred to the State on all significant aspects of State restructuring of California electric power markets and market rules - - including those aspects which directly implicated this Commission's exclusive jurisdiction. In today's order, we find it necessary to fundamentally change some of the wholesale market rules that arose from the original State restructuring and were accepted by us. Unless we take this step, and unless the State also expeditiously takes the step of changing its market restrictions and dealing with other relevant matters within its jurisdiction, wholesale markets will continue to be dysfunctional and electric consumers will continue to be at risk of unnecessary price volatility and power interruptions. Simply put, we must not only stop the current electric market hemorrhaging and restore credibility to the electric markets in the West, but we must ensure that this situation does not recur.

Given the gravity of the situation and the need to expeditiously implement remedies that will avert a recurrence of the problems in California last summer as well as the problems in the past few weeks, our order today is forward-looking. This order does not address issues associated with retroactive refund and retroactive remedial authority issues. Today we concentrate on the implementation of those market reforms that are needed immediately. We emphasize that critical long-term reforms such as siting and demand response also must be addressed immediately by relevant State authorities.

The Commission herein adopts the following remedial measures:

(1) **Elimination of the Mandatory PX Buy-Sell Requirement.** The Commission is eliminating the requirement that the investor owned utilities in California (IOUs) sell all of their generation into, and buy all their generation from, the California Power Exchange (PX). This will release the entirety of the IOUs' 40,000 MWs of peak load from exposure to the spot market and will allow or require the following:

(a) ***25,000 MWs immediately returned to State regulation***. On the date of this order, 25,000 MW of generation owned by or under contract to the IOUs, which the State had required to be sold at wholesale into the PX, may be sold directly at retail by the IOUs subject to the regulation of California. The State is free as of date of issuance of this order to regulate this power on a cost-of-service basis, subject to a cost cap, or in any way it sees fit.

(b) ***Release of load to bilateral markets and prudent risk management.*** The release of all 40,000 MWs from mandatory exposure to the spot market will permit the IOUs to move their purchase power needs to bilateral long-term contracts and adopt a balanced portfolio of contracts to mitigate cost exposure. This is critical to limiting extreme price volatility for California consumers. However, this cannot occur unless the California Commission also removes its requirement that IOUs buy only through the PX and unless it provides IOUs with some certainty with respect to contracting. It is critical that the California Commission give timely and predictable approval of the prudence of a balanced portfolio of long and short-term contracts.

(c) ***Termination of PX wholesale rate schedules.*** The Commission will terminate the PX's wholesale rate schedules which enable it to continue to operate as a mandatory power exchange. Termination will be effective as of the close of the April 30, 2001 trading day. These tariffs may be re-instituted at a later time but that depends upon the California Commission's willingness to remove its mandatory buy requirement and to develop prudence benchmarks for bilateral purchases, or other changed circumstances. We see great value in this and other power exchanges but cannot assure just and reasonable rates in the presence of a mandatory power exchange in these circumstances.

(2) **Benchmark Price for Wholesale Bilateral Contracts.** To provide guidance to the market participants and our input to the California Commission with respect to prudent contracting, we adopt a price benchmark for assessing prices of long-term electric supply contracts. We would expect to use this benchmark in assessing any

complaints regarding the justness and reasonableness of pricing of such long-term contracts negotiated under current market conditions.

(3) **Penalties for Underscheduling Load.** Market participants will be required to schedule 95 percent of their loads prior to real-time and will be subject to a penalty for deviations in scheduling in excess of five percent of an entity's hourly load requirements, with disbursement of revenues to all loads that scheduled accurately.

(4) **Market Monitoring and Price Mitigation for ISO and PX Spot Markets.** The above remedies will shrink the ISO's real-time market to approximately 5 percent of load. In other words, only about 2,000 MWs (instead of 6,000 MWs) will be purchased in the real-time, sometimes volatile, markets. However, to ensure that prices in the ISO and PX spot markets are just and reasonable, the Commission will provide appropriate market monitoring and price mitigation:

(a) ***"Real-Time" Mitigation.*** The Commission directs a technical conference for purposes of developing a comprehensive and systematic monitoring and mitigation program which incorporates appropriate thresholds and screens and specific mitigation measures if those thresholds and screens are breached. A proposed plan is to be submitted to the Commission no later than March 1, 2001 so that an acceptable plan can be reviewed by the Commission and in place by May 1, 2001.

(b) ***$150 Breakpoint for Interim Period.*** The Commission will establish a $150 per MW breakpoint which will be used for the interim period before "real time" mitigation is implemented.

- Sellers bidding at or below this breakpoint will receive the market clearing prices, but not more than $150 per MW.

- If sellers bidding above this breakpoint are needed to clear the market, they will receive their actual bids. However, they will be subject to certain reporting and monitoring requirements to ensure that market power is not exercised and to ensure that rates remain just and reasonable. Certain refund conditions will continue to apply; however, unless the Commission issues written notification to a seller that its transaction is still under review, refund potential on a transaction will close after 60 days.

(5) **Independent Governing Board of ISO.** The current ISO stakeholder governing board must be replaced with a non-stakeholder board, with members to be

independent of market participants. In the interim, the ISO Governing Board members, on January 29, 2001, are required to turn over decision-making power and operating control to the management of the ISO; however, they will be permitted to continue functioning as an advisory committee that provides input to ISO management until such time as a new Board is seated or until April 27, 2001, whichever occurs sooner. We note that under the Commission's Order No. 2000 rule on regional transmission organizations (RTOs), the California ISO's RTO filing pursuant to the rule must address the independence criterion contained in the rule.

(a) ***State-Federal Discussions on Board Selection.*** In a later order, the Commission will establish procedures to discuss with state representatives the process for selection of ISO Board members.

(6) **Generation Interconnection Procedures For ISO and IOUs.** We require both the ISO and the three California IOUs to file generation interconnection procedures.

Background

A. August 23 Order

On August 2, 2000, in response to significant increases in prices for energy and ancillary services in California, SDG&E filed a complaint in Docket No. EL00-95-000. This complaint, filed against all sellers of energy and ancillary services into the ISO and PX markets subject to the Commission's jurisdiction, requested that the Commission impose a $250 price cap for sales into those markets. The Commission denied this request in an order issued August 23, 2000, on the grounds that SDG&E had not provided sufficient evidence to support an immediate seller's price cap. [1] However, in that order, the Commission instituted formal hearing proceedings under section 206 of the Federal Power Act to investigate the justness and reasonableness of the rates of public utility sellers into the ISO and PX 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. The Commission held the hearing in abeyance pending the completion of a separate staff fact-finding investigation of the conditions of bulk power markets that was to be completed no later than November 1, 2000.

In addition, the Commission discussed the role of refunds in the proceeding, and noted that refunds were discretionary and may not be the appropriate remedy to address competitive problems that may be identified. The order further stated that any decision

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

whether to direct refunds would be based on findings regarding just and reasonable rates and a balancing of consumer and investor interests. The Commission established a refund effective date of 60 days after publication of notice of the Commission's intent to institute a proceeding in the Federal Register.[2]

B. Staff Report

Staff completed its fact-finding investigation of California markets in October, and submitted its report to the Commission.[3] The Staff Report identified three factors that contributed to high electricity prices. First, market forces in the form of significantly increased power production costs combined with increased demand due to unusually high temperatures and a scarcity of available generation resources throughout the West and California in particular played a major role. Second, existing market rules exacerbated the situation by exposing the three investor-owned utilities (IOUs) to the volatility of the spot market without affording them the ability to mitigate the price volatility and by promoting underscheduling in the PX, thereby increasing the amount of demand and supply that appeared in the ISO's real-time market. Third, the Staff Report noted evidence suggesting that sellers had the potential to exercise market power, although there were insufficient data to make determinations about the exercise of market power by individual sellers.[4]

C. November 1 Order

The Commission issued an order on November 1, 2000 proposing measures to remedy the problems identified in the Staff Report.[5] The Commission found that the "electric market structure and market 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

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[2] Id. at 61,608.

[3] Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities - - Part 1, November 1, 2000 (Staff Report).

[4] The Staff Report indicated some attempted exercise of market power, if the standard of bidding above marginal cost is used. Staff Report at 1 - 4. The November 1 Order did not establish any standard for determining market power.

[5] San Diego Gas & Electric Company, et al., 93 FERC ¶ 61,121 (2000), reh'g pending (November 1 Order).

conditions." [6] The order noted that "While this record does not support findings of specific exercises of market power, and while we are not able to reach definite conclusions about the actions of individual sellers, there is clear evidence that the California market structure and rules provide the opportunity for sellers to exercise market power when supply is tight, and can result in unjust and unreasonable rates under the FPA." [7]

To deal with these flaws, the November 1 Order proposed remedies intended to reduce over-reliance on spot markets in California, and attempted "to balance, on the one hand, holding overall rates to levels that approximate competitive market levels for the benefit of consumers, with, on the other hand, inducing sufficient investment in capacity to ensure adequate service for the benefit of consumers." [8] The order proposed, effective 60 days after the date of the order, (1) to eliminate the requirement that the investor-owned utilities (IOUs) must buy and sell power through the PX, (2) to require market participants to schedule 95 percent of their transactions in the Day-Ahead markets or be subjected to a penalty charge; (3) to replace the existing PX and ISO stakeholder boards with independent non-stakeholder boards; and (4) to require the filing of generation interconnection procedures.

The order also identified longer-term structural reforms that must be addressed, including: (1) consideration of market rules to ensure meeting reserve requirements; (2) exploration of alternatives to the single price auction format; (3) elimination of the requirement for balanced schedules; (4) improved market monitoring and market mitigation strategies; (5) submission of a congestion management redesign proposal; and (6) consideration of demand bidding programs for the ISO and Scheduling Coordinators. In addition, the order urged state officials to take certain actions within their exclusive jurisdiction, including accelerating siting of needed generation and transmission capacity, developing additional demand-side response programs at the retail level, and eliminating impediments to forward contracting.

Also, to ensure fair prices while various market reforms were being put in place, the order proposed additional temporary measures to mitigate prices, including modification of the single price auction so that bids above $150/MWh could not set the market clearing price that is paid to all bidders and imposing certain reporting and monitoring requirements for transactions and bids above the $150/MWh breakpoint, as well as retaining a refund obligation for sales into the ISO and PX markets for the period October 2000 through December 2002.

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[6] Id. at 61,349-50.

[7] Id. at 61,350.

[8] Id.

The November 1 Order changed the refund effective date contemplated in the August 23 Order from 60 days after publication of notice in the Federal Register, October 29, 2000, to 60 days after the date of SDG&E's complaint, October 2, 2000, effectively granting the requests for rehearing from SoCal Edison and PG&E on this issue. The order also contains extensive discussion of the Commission's authority to direct refunds, for the periods both before and after the refund effective date, as discussed below.

The Commission explained why a paper hearing is adequate to resolve the matters before it, and established a period through November 22, 2000 for the submission of comments and supporting evidence. In addition, the Commission announced its intent to convene a public conference on November 9, 2000 and to issue a final order adopting and directing remedies for California's markets before the end of the calendar year. Finally, the Commission rejected proposed tariff amendments filed by the PX and the ISO requesting or extending price caps for their markets.

D. Related Complaints and Other Filings

1. Joint Complaint in Docket No. EL00-97-000

On August 3, 2000, Reliant Energy Power Generation, Inc., Dynegy Power Marketing, Inc., and Southern Energy California, L.L.C. (Joint Complainants) jointly filed a complaint and request for fast-track processing pursuant to Rule 206 of the Commission's Rules of Practice and Procedure [9] requesting the Commission to find that the ISO must compensate participating generators, Scheduling Coordinators, or other sellers (collectively, Market Participants) for their actual damages and lost opportunity costs in the event that the ISO curtails energy exports scheduled by a Market Participant. Joint Complainants further request that the Commission find that any effort by the ISO to limit payment for curtailed energy exports to ISO-capped prices would violate the Commission's order in Morgan Stanley Capital Group Inc., 92 FERC ¶ 61,112 (2000) (Morgan Stanley).

In support of the complaint, Joint Complainants observe that under section 5.6.1 of the ISO Tariff, the ISO may curtail firm exports during a Stage Three emergency. Joint Complainants state that this tariff language was designed to accommodate situations like transmission constraints or unexpected problems with the grid that, among other things, could prohibit power from being shipped out of the state to avoid transmission overloads, voltage problems, or stability problems. Joint Complainants assert, however, that system emergencies will likely also be triggered by supply shortages that are a direct result of the ISO's new, lower price caps. In effect, Joint Complainants argue, the ISO is risking the creation of system emergencies by its own decision to lower price caps below market

[9] 18 C.F.R. § 385.206 (2000).

price, thus driving Market Participants to seek other markets and resulting in shortages in the ISO control area.

Furthermore, Joint Complainants contend that the ISO Tariff does not specify how Market Participants are to be compensated if their energy exports are curtailed by the ISO in response to an ISO-declared system emergency. Joint Complainants state that under standard arrangement for export transactions for firm delivery, Market Participants could be liable to the would-be buyer for liquidated damages for failure to deliver. Joint Complainants also state that in addition to liquidated damages, if export schedules are curtailed, Market Participants will lose the opportunity to sell the exported energy at competitive market prices. Therefore, Joint Complainants contend, if the ISO terminates an export transaction, the ISO should be made to hold the generator harmless from any damages that result from the ISO's decision and to provide the generator full recovery of its opportunity cost on the canceled export sale.

Notice of Joint Complainants' filing was published in the Federal Register, 65 Fed. Reg. 48,982 (2000), with comments, protests, and motions to intervene due on or before August 14, 2000. The California Commission filed a notice of intervention, protest, and request for summary disposition asserting that the complaint is factually unsupported, legally unfounded, complains of conduct consistent with the ISO's authority under pertinent Commission decisions, and seeks to avoid the ISO's Commission-authorized price cap in order that Joint Complainants may exercise market power and impose unjust and unreasonable rates. Timely motions to intervene, comments, protests, and answers were filed by the entities listed in Appendix A. In addition, El Paso Merchant Energy, L.P., filed an untimely motion to intervene.

Three intervenors as well as a number of individuals oppose the complaint, asserting, among other things, that the complaint is factually unsupported and legally inaccurate. Six intervenors filed comments supporting the complaint in its entirety. The Oversight Board expresses a number of concerns regarding the complaint but agrees that a seller's compensation for bona fide sales [10] should not be limited by the ISO's bid cap if such a sale were for an amount higher than the bid cap currently in place. PG&E incorporates by reference its comments in the consolidated hearing proceeding and requests consolidation of the instant complaint therein.

On August 14, 2000, the ISO filed an answer to the complaint. On August 18, 2000, Joint Complainants filed a motion to reply to certain answers to the complaint.

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[10] I.e., sales which are not those the Oversight Board believes to be imprudent or infeasible. See Oversight Board at 3-4.

2. California Oversight Board's Complaint in Docket No. EL00-104-000

On August 29, 2000, the Oversight Board filed a complaint pursuant to Rule 206 of the Commission's Rules of Practice and Procedure asking the Commission to find that the wholesale markets in California are not workably competitive and to take such actions as are necessary to ensure that wholesale prices for energy and ancillary services are just and reasonable. In addition, the Oversight Board requests that the Commission affirmatively direct the ISO to maintain bid caps at a level no greater than $250 per MWh for energy, $250 per MW for ancillary services, and $100 per MW for Replacement Reserves. Finally, the Oversight Board requests that its complaint be consolidated with the consolidated hearing proceeding.

The Oversight Board explains that its complaint is based on its conclusion that respondent Sellers [11] and Scheduling Coordinators, [12] individually and collectively, have market power and exercise market power commanding prices far above rates that would be determined by cost-of-service ratemaking or prices voluntarily agreed to by buyers and sellers in a workably competitive market. According to the Oversight Board, such pricing occurs with regularity during periods of high demand; [13] at some times, respondent Sellers and Scheduling Coordinators know with substantial certainty that the ISO will be accepting all bids regardless of their level, while at other times a number of those entities know that they control enough capacity in relation to the system demand and supply margin that they have a high likelihood of successfully setting the market clearing price. Thus, the Oversight Board asserts, under both sets of circumstances, resulting prices cease to bear

[11] The Oversight Board indicates that the term "Sellers" includes all entities with market-based rate authority for sales in California as well as non-Commission jurisdictional sellers, including but not limited to, power marketers, traditional investor-owned utilities, new generation owners, Federal power administrations, publicly-owned utilities (including agencies of the State of California and agencies of other states), local agencies (both in-state and out-of-state), and sellers located beyond the borders of California. Complaint at 3, n.5.

[12]The Oversight Board believes that Scheduling Coordinators are well-positioned to take advantage of gaming opportunities in the ISO and the PX markets because they often bid on behalf of more than one seller. The Oversight Board asserts that the benefits of divestiture – reducing concentration of ownership – can be undermined if a single Scheduling Coordinator is able to bid on behalf of multiple suppliers. Complaint at 3, n.6.

[13]The Oversight Board contends that the threshold level for such demand is 33,000 MW or higher. Complaint at 5.

any relationship to the cost of supplying the service and instead reflect bids made with the knowledge that supply will have to be taken regardless of the price at which it is offered.

Further, the Oversight Board asserts that because Sellers and Scheduling Coordinators know with practical certainty that they will be needed during periods of high demand, they have diminished incentive to offer service in the forward markets (e.g., the PX) at a price lower than what they could expect to secure if they waited for later ISO markets. [14] As a result, the Oversight Board requests that the Commission recognize that the ISO's bid cap is a necessary – and not merely allowable – damage mitigation measure until the Commission finds affirmatively that California market prices are just and reasonable. The Oversight Board also requests that the Commission exercise its responsibilities under sections 205 and 206 of the Federal Power Act by directing the ISO to maintain a cap of not more than $250 for bids into the ISO's energy and ancillary services markets, and not more than $100 for bids into the ISO's Replacement Reserves markets (which, the Oversight Board notes, are the ISO's currently-effective bid caps). [15]

Notice of the Oversight Board's filing was published in the Federal Register, 65 Fed. Reg. 54,248 (2000), with comments, protests, and motions to intervene due on or before September 18, 2000. The California Commission filed a notice of intervention supporting the Oversight Board's request that the Commission find that California's markets are not workably competitive and asking that the Commission take such action as necessary to ensure that California's wholesale rates are just and reasonable. Timely motions to intervene, comments, protests, and answers were filed by the entities listed in Appendix A.

Fifteen intervenors filed comments opposing the Oversight Board complaint, arguing that the Oversight Board failed to adequately justify its request and that price caps are counterproductive and harmful to a competitive market. Four intervenors filed comments in support of the complaint, including support for the request for consolidation. Motions to dismiss in part for lack of jurisdiction were filed by Cities/M-S-R, Modesto, and TANC. NCPA filed an answer and motion to dismiss as to non-jurisdictional entities.

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[14] In support of its assertion, the Oversight Board cites several instances during May and June 2000 where both the PX's and the ISO's market prices were markedly elevated during the same time-periods.

[15] The Oversight Board asserts that a cap of $250 in the ISO's markets is sufficient to allow generators to recover their variable costs and earn significant additional revenues. In support of its assertion, the Oversight Board refers to the complaint filed by SDG&E on August 2, 2000, in Docket No. EL00-95-000, whereby SDG&E contended that hourly operating costs for an inefficient gas-fired California generating unit would be $147 per MWh (based on then-current natural gas prices). Complaint at 8.

On October 3, 2000, the Oversight Board filed an answer in response to various motions to dismiss the complaint. On October 18, 2000, Pinnacle filed an answer in response to the answer of the Oversight Board.

3. California Municipal Utilities Association's Complaint in Docket No. EL01-1-000

On October 6, 2000, CMUA filed a complaint pursuant to Rule 206 of the Commission's Rules of Practice and Procedure requesting that the Commission impose cost-based rates on all Commission-jurisdictional sellers into the ISO and the PX and that the Commission consolidate the complaint with the consolidated hearing proceeding. In support of its complaint, CMUA argues that California consumers are experiencing unprecedented, high, sustained wholesale power prices. Further, CMUA also argues that the California market is not workably competitive and that the framework to correct the problems therein is not in place.

In sum, CMUA contends that although the ISO is considering congestion management and other reforms to improve market performance, such modifications will not solve California's market problems. According to CMUA, the reality is that the infrastructure necessary for workable competition, including investment in generation and transmission facilities and real-time demand responsiveness, will not be in place any time soon. CMUA acknowledges that many of the market rule modifications may help lower overall costs to consumers as compared to current prices; however, CMUA asserts those changes will not improve the fundamentals of the market. Thus, CMUA concludes, the only available remedy is the reinstatement of cost-of-service ratemaking for jurisdictional sellers until such time as fundamental changes can be made and markets can be found to be workably competitive.

Notice of CMUA's filing was published in the Federal Register, 65 Fed. Reg. 61,315 (2000), with comments, protests, and motions to intervene due on or before October 26, 2000. The California Commission filed a notice of intervention raising no issues. Timely motions to intervene, comments, protests, and answers were filed by the entities listed in Appendix A. In addition, an untimely motion to intervene was filed by the City of Vernon, and an untimely joint motion to intervene was filed by Dynegy, et al.

Thirteen intervenors filed comments opposing CMUA's complaint, asserting that CMUA failed to adequately support its position on that matter, that cost-based rates would inhibit the formation of a competitive market within California, and that the complaint is premature in light of the consolidated hearing proceeding. Four intervenors filed comments supporting the complaint, contending, among other things, that cost-based rates are a superior alternative to price caps. PG&E and SoCal Edison each filed motions to intervene and comments arguing that the Commission should adopt the market mitigation measures previously outlined in their Joint Motion for Emergency Relief. [16] One individual, Mr. Bruce W. Simonton, filed comments urging the Commission to consider the adverse impact that unregulated generation plant downtime will have on cost-based rate determinations.

4. CAlifornians for Renewable Energy, Inc.'s Complaint in Docket No. EL01-2-000

On October 26, 2000, as amended on October 31, 2000, CAlifornians for Renewable Energy, Inc. (CARE) filed a complaint pursuant to Rule 206 of the Commission's Rules of Practice and Procedure petitioning the Commission to: (1) rectify unjust and unreasonable prices stemming from the wholesale markets for energy and ancillary services operated by the ISO and the PX; (2) find that the wholesale markets in California are not workably competitive; (3) make findings that the events and circumstances surrounding the June 14, 2000 rolling outage in the San Francisco Bay Area warrant investigations by the United States Department of Justice (DOJ) of anti-trust activities in restraint of trade and of alleged civil rights violations rendered by various entities; [17] and (4) include in the aforementioned investigations the identification of injury, loss of life, disability, or hospitalization associated with the June 14, 2000 rolling outage. CARE also requests that the Commission consolidate the complaint with the consolidated hearing proceeding.

In support of its complaint, CARE contends that various entities are currently involved together in an ISO/generator trust to drive up the price of electricity and to justify expedited power plant construction in California to further maximize generator profits. Further, CARE also contends that low-income and minority communities were disparately impacted by the June 14, 2000 rolling blackouts in the San Francisco Bay Area. Finally, CARE argues that the June 14, 2000 rolling blackouts created an eminent threat to public health and safety, and overburdened Northern California emergency services, hospitals, and law enforcement with unanticipated costs to public and private funds.

Notice of CARE's amended complaint was published in the Federal Register, 65 Fed. Reg. 70,340 (2000), with comments, protests, and motions to intervene due on or before November 30, 2000. The California Commission filed a notice of intervention

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[16] See the October 16, 2000 Joint Motion for Emergency Relief and Further Proceeding filed in Docket No. EL00-95-000, et al., by PG&E, SoCal Edison, and TURN.

[17] Those entities are: IEP; all sellers of energy and ancillary services into markets operated by the ISO and the PX; all Scheduling Coordinators acting on behalf of the aforementioned sellers; the ISO; and the PX.

raising no issues. Timely motions to intervene, comments, protests, and answers were filed by the entities listed in Appendix A.

Twelve intervenors filed comments opposing CARE's complaint in its entirety, contending that CARE failed to adequately support its claims, that the complaint is premature in light of the consolidated hearing proceeding, and that CARE's petition for DOJ investigations is beyond the scope of the Commission's jurisdiction. SMUD filed comments opposing the majority of CARE's complaint but agreeing that the wholesale markets in California should be found to be not workably competitive. IEP filed a conditional answer and motion to dismiss arguing the complaint should be dismissed in its entirety or, in the alternative, that the Commission should (1) dismiss the complaint as to IEP (a non-Commission-jurisdictional industry trade group) and (2) consolidate the complaint with the consolidated hearing proceeding. SoCal Edison filed comments arguing that the Commission should adopt the market mitigation measures previously outlined in the Joint Motion for Emergency Relief discussed above. Motions to dismiss in part for lack of jurisdiction were filed by Cities/M-S-R, Modesto, and TANC. NCPA filed an answer and motion to dismiss as to non-jurisdictional entities.

5. Puget Sound Energy, Inc.'s Complaint in Docket No. EL01-10-000

On October 26, 2000, Puget Sound filed a complaint pursuant to Rule 206 of the Commission's Rules of Practice and Procedure petitioning the Commission for an order capping the prices at which sellers subject to Commission jurisdiction, including sellers of energy and capacity under the Western Systems Power Pool Agreement, may sell energy or capacity in the Pacific Northwest's [18] wholesale power markets. Specifically, Puget Sound seeks an order that prospectively caps the prices for wholesale sales of energy or capacity into the Pacific Northwest at a level equal to the lowest cap on prices established, ordered, or permitted by the Commission for wholesale purchases in, or wholesale sales of energy or capacity to or through the markets operated by the ISO or the PX.

Puget Sound asserts that price caps of the kind requested for sales to the ISO and the PX and those instituted by the ISO for purchases are – absent equivalent price caps on wholesale sales of energy and capacity into the Pacific Northwest – fundamentally unfair to Pacific Northwest public utilities and are antithetical to the development of a fair competitive wholesale power market within the Western Interconnection. In support of its assertion, Puget Sound argues that uneven application of price caps upsets the balance of purchase and sale market prices between California and the Pacific Northwest and violates

[18] Puget Sound indicates that, as used in its complaint, the term "Pacific Northwest" has the meaning set forth in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. § 839a(14) (2000).

section 206 of the FPA because such uneven application is unjust, unreasonable, and unduly discriminatory or preferential. Further, according to Puget Sound, the effect of such disparate treatment is to expose wholesale purchasers in the Pacific Northwest to uncapped prices when they need power (e.g., to meet winter demand) and yet restrict their ability to offset the costs of such purchases with uncapped prices when they have surplus power (e.g., due to favorable hydroelectric generation conditions) for sale to California. Thus, Puget Sound concludes, fairness and the desire to avoid unnecessary market distortions within the integrated California and Pacific Northwest market dictate that the Commission institute Puget's requested price cap.

Notice of Puget's filing was published in the Federal Register, 65 Fed. Reg. 66,896 (2000), with comments, protests, and motions to intervene due on or before November 16, 2000. [19] Timely motions to intervene, comments, protests, and answers were filed by the entities listed in Appendix A. In addition, untimely motions to intervene were filed by the Oversight Board, El Paso Merchant Energy, LP, Bonneville Power Administration (Bonneville), and Western Area Power Administration (WAPA).

Six intervenors filed comments opposing Puget's complaint, arguing that Puget Sound failed to adequately support its assertions, that the complaint is unnecessary in light of the consolidated hearing proceeding, that the Northwest has no organized electricity market to which a price cap may be rationally applied, and that price caps in the Northwest would inhibit the formation of a competitive market within that region. SoCal Edison filed comments supporting the complaint, contending that price caps throughout the entire Western region will alleviate incentives for suppliers to move their supply outside the PX (e.g., the ISO or outside of California) for the purpose of receiving higher prices in other markets. PacifiCorp filed a motion for clarification, for more definition, and for a stay, asserting that Puget Sound should be required to provide a much greater level of specificity in its complaint and that the complaint should be stayed pending the outcome of the consolidated hearing proceeding.

On November 30, 2000, Puget Sound filed an answer to PacifiCorp's motion for clarification, for more definition, and for a stay.

6. ISO's Offer of Settlement in Docket Nos. EL00-95-003 and EL00-98-003

[19] We note that several intervenors filed pleadings in the instant docket on November 17, 2000. However, insofar as the Commission closed its docket operations at 1:00 p.m. on November 16, 2000, and the deadline of November 16 is not mandated by statute, we hereby accept those pleadings as timely filed.

On October 20, 2000, the ISO submitted a proposed Offer of Settlement which, according to the ISO, is intended to address a core issue in the pending proceeding – i.e., the need to have in place as soon as practicable a system-wide market power mitigation regime. The ISO indicates that the Offer of Settlement is not intended to displace the congestion management and market redesign efforts that are nearing completion. [20] Rather, the ISO states that the Offer of Settlement is complementary to those initiatives and addressed to issues which cannot be ignored in the interim and that are likely to persist even with market reformation, for they are attributable not to design inadequacies but to infrastructure insufficiency.

In sum, the ISO proposes that a price cap be established at $100/MWh with the following exemptions: [21] (1) if an owner demonstrates that a payment of $100/MWh would be insufficient to cover the variable operating cost of a unit and make some reasonable contribution to fixed cost recovery, a higher cap would be fixed for that unit but that price would not establish the market clearing price; (2) generation fired by renewables would not be capped; (3) owners and operators whose units do not exceed 50 MW would be exempt; (4) incremental generation (i.e., additions to existing units and new units) would be exempt; (5) any owner or marketer who demonstrates that it has committed 70 percent or more of the availability of its in-state portfolio to an in-state load-serving entity for a term extending at least through October 15, 2002, would be exempt; and (6) imports would be exempt. Exempt units would be subject to whatever higher damage-control price cap is in place.

Moreover, as a corollary measure, the ISO proposes that load be required to forward contract for no less than 85 percent of projected requirements, as adjusted by season and time-of-day. Generation currently owned by load-serving entities would be counted in satisfaction of the 85 percent requirement. Finally, Scheduling Coordinators would be required to schedule no less than 90 percent of load in the day-ahead market and no less than 95 percent in the hour-ahead market. A charge would be assessed against load and generation that appears in real-time and that exceeds 1.10 and 1.05 times the balanced schedules submitted, respectively, in the day-ahead and hour-ahead markets, and out-of-

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[20]See November 1 Order, 92 FERC at 61,356.

[21]The ISO states that a price cap of $100/MWh was selected because the analysis undertaken by the ISO's Department of Market Analysis indicated that during times when the market is workably competitive, it clears at prices below $100/MWh. Further, the ISO proposes to index the price cap to an assumed monthly average burnertip price of natural gas at $7/MMBtu. To the extent that the price of natural gas deviates by more than a threshold level – e.g., 5 percent – the ISO indicates that its intention would be to adjust the price cap to reflect that cost change.

market costs would be charged to underscheduled load and to generation appearing in real-time in excess of balanced schedules.

With respect to its proposed price cap, the ISO indicates its belief that the combined effect of a $100/MWh price cap with the availability of an exemption from that limitation will incline those that own or control generation resources to forward contract. Further, the ISO asserts that, by requiring forward contracting to the extent proposed, UDCs, with the concurrence of the California Commission, should be in a position to secure for their customers with the most inelastic loads – i.e., residential and small commercial customers – adequate supplies at fixed rates.

The PX filed comments indicating concern that the Offer of Settlement is unclear in some respects and incomplete in others, that it addresses only some of the market corrections that need to be considered, and that other potential approaches be given equal consideration during any settlement process. PG&E filed comments complaining that the Offer of Settlement fails to address remedies for the market dysfunction over the past Summer and fails to provide any proposals for preventing the repeat of that dysfunction.

7. ISO's Tariff Amendment No. 30 in Docket Nos. EL00-95-002 and EL00-98-002

In the August 23 Order, the Commission noted that the ISO procures on a daily basis only the resources necessary for the operating day, and we expressed concern that this practice not only puts pressure on the grid operator to secure needed resources at the last minute but also is uneconomical. Consequently, we directed the ISO to immediately institute a more forward approach to procuring the resources necessary to reliably operate the grid. [22]

On September 11, 2000, in response to our above direction, the ISO filed Tariff Amendment No. 30. [23] The ISO proposes to amend section 2.5.3.1.5 of the tariff to clarify the ISO's authority to contract without first soliciting bids. The ISO indicates its belief that while the current tariff provision does not specify, as a precondition for contracting, that a competitive solicitation must be conducted, clarification of any ambiguity is appropriate. Further, the ISO asserts that apart from the fact that a formal bid process would be

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[22] August 23 Order, 92 FERC at 61,608.

[23] The ISO requests waiver of the Commission's 60-day notice requirement and immediate acceptance of its proposed tariff amendment (i.e., an effective date coincident with the date of the tariff amendment's filing). We note that the 60-day notice requirement does not apply to compliance filings such as this.

inconsistent with the time imperatives, particularly if it is possible to obtain relief for the remaining weeks of the peak season, individual negotiation is likely to produce better results for consumers.

In addition, the ISO proposes to amend section 2.3.5.1.8 of the ISO Tariff and to add a new section 2.3.5.1.9 for the purpose of allocating the costs of any forward contracts to those Scheduling Coordinators who are responsible for the incurrence of such costs, i.e., to those who deviate, in real-time, from schedules, in proportion to their deviation. According to the ISO, fairness, as well as providing appropriate economic incentives to Scheduling Coordinators to align their forward and real-time schedules, dictates this allocation. In addition, the ISO indicates that to the extent that such allocation is not sufficient to make the ISO whole for the costs it incurs, any remaining balance will be incrementally flowed through the Tariff's neutrality clause (i.e., section 11.2.9) as charges incurred for the benefit of all market participants.

Notice of the ISO's filing was published in the Federal Register, 65 Fed. Reg. 56,881 (2000), with motions to intervene and protests due on or before October 2, 2000. The California Commission filed a motion to intervene raising no issues.

Fifteen intervenors filed comments opposing the ISO's proposal, contending that the Commission should expressly limit the ISO's use of forward contracting and arguing that the ISO's proposed cost allocation methodology is unjust and unreasonable. Additionally, Southern Cities filed a limited protest regarding only the ISO's proposed cost allocation methodology. Comments generally supporting the ISO's proposal were filed by APX; however, APX also raises concerns regarding limitation of the ISO's use of forward contracting.

On October 18, 2000, the ISO filed an answer to the various motions to intervene, comments, and protests.

8. California Commission's Motion to Compel

On November 6, 2000, the California Commission filed a motion for adoption of a protective order and to compel production of documents (Motion). The California Commission explains that it needs this Commission's assistance to obtain the information in question [24] from certain generators and marketers (Suppliers) both for purposes of

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[24] The categories of information sought by the California Commission include: (1) profit and loss statements and unconsolidated income statements; (2) documents showing respondents' transaction-specific trades of energy occurring outside the PX and ISO

(continued...)

providing comments in this proceeding and for purposes of the California Commission's own investigation into the same matters. The California Commission further requests that the Commission adopt a proposed protective order. The California Commission explains that its proposed protective order is derived from the Commission ALJs' Model Protective Order, with modifications to permit the sharing of "Protected Materials" for use in related state proceedings, and to limit disclosure of certain information to "government eyes only."

The following entities filed answers opposing the California Commission's Motion: Duke; Reliant Energy Power Generation, Inc. and Reliant Energy Services, Inc. (jointly); Williams; Dynegy, et al.; and Southern Energy, Inc., on behalf of itself and all of its subsidiaries and affiliates which are parties to or intervenors in this proceeding. Primary objections to the Motion include: (1) discovery has not been authorized in this proceeding, and FERC precedent does not allow discovery in paper hearings generally; (2) discovery is not needed because FERC already fully investigated the functioning of California's markets, and Suppliers have already produced ample information to FERC staff; (3) allowing discovery for only one party is discriminatory; (4) the subpoenas are objectionable as they are overly broad, unduly burdensome, duplicative, and/or irrelevant; and (5) the proposed protective order does not adequately restrict access to, and use of, the requested information.

In addition, SoCal Edison responded in support of the Motion, and Northern California Municipals [25] answered in support of an order compelling production of documents but objected to aspects of the proposed protective order.

9. California Governor's Comments

On December 1, 2000, Governor Gray Davis submitted his suggested changes to the November 1 Order and outlined his emerging plan to reform the California market. Governor Davis requests that the Commission reverse its November 1 Order to provide retroactive refunds. In addition, Governor Davis does not believe that the $150/MWh breakpoint will provide any protection and requests that the Commission impose bid caps in

[24](...continued)
markets, within California or the Western System Coordinating Council; (3) documents showing respondents' variable operating costs and fixed costs; and (4) documents showing respondents' maintenance and outage schedules. Motion at 10. The California Commission generally seeks this information for the period commencing April 1, 1998.

[25]Northern California Municipals include the Transmission Agency of Northern California, the M-S-R Public Power Agency, Modesto Irrigation District, and the Cities of Redding, Santa Clara, and Palo Alto, California.

the $100/MW range for the next 36 months. Governor Davis's emerging plan calls for using his "green team" to develop new and creative approaches to overcoming environmental restrictions to permit the construction and operation of new power plants. Governor Davis recognizes that forward contracts are an important tool to moderate price volatility and ensure reliability and asks the California Commission to develop benchmarks for forward contracts. Governor Davis also calls upon the California Commission to reduce barriers to locating distributed generation and cogeneration and implement programs to provide real-time price signals and demand-side management. Lastly, Governor Davis agrees with the Commission that the existing PX and ISO stakeholder boards must be replaced and he intends to propose legislation to replace the stakeholder boards with independent boards that are accountable for their actions.

E. December Orders

Beginning in mid-November, the ISO experienced numerous occasions of insufficient reserve margins and emergency conditions forcing it to serve increasingly large portions of its total Control Area load through its real-time Imbalance Energy market. On December 8, 2000, the ISO filed Tariff Amendment No. 33 in Docket No. ER01-607-000, seeking expedited consideration of tariff revisions to address emergency reliability conditions. The filing sought three modifications of the ISO's tariff: (1) immediate implementation of an interim price mitigation proposal based on the breakpoint concept that was proposed in the November 1 Order (at $250/MWh) to encourage greater participation of generators in its markets; (2) provision of penalties on generators that fail to respond to dispatch instructions during a system emergency, to become effective December 8, 2000; and (3) allocation of the costs of obtaining additional energy to Scheduling Coordinators who rely on the ISO's real-time Imbalance Energy market, as an incentive to loads to purchase energy in forward markets. The ISO requested an effective date of December 12, 2000 for the third modification.

The Commission approved the tariff revisions in an order issued December 8, 2000, with the effective dates requested by the ISO. [26]

Also on December 8, 2000, the Commission issued an order waiving certain regulations pertaining to QFs, effective for the period December 8 through December 31,

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[26] California Independent System Operator Corporation, 93 FERC ¶ 61,239 (2000) (December 8 Order).

2000. [27] The waiver allows certain QFs to sell their excess production to load location in California through negotiated bilateral contracts to alleviate the inadequate generation resources in California.

Discussion

A. Procedural Matters

Numerous additional entities moved to intervene in the consolidated hearing proceeding on or before November 22, 2000. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, [28] these timely, unopposed motions to intervene serve to make those who filed them parties to this proceeding. These parties are included in the list of intervenors included in Appendix A. In addition, the Steel Manufacturers Association filed a motion to intervene out-of-time. In view of the early stage of the consolidated hearing proceedings and the absence of any undue prejudice or delay, we find good cause to grant this untimely, unopposed motion to intervene.

The timely, unopposed motions to intervene in the related complaint proceedings (Docket Nos. EL00-97-000, EL00-104-000, EL01-1-000, EL01-2-000, and EL01-10-000) serve to make those who filed them parties to the respective proceedings, pursuant to Rule 214 of the Commission's Rules of Practice and Procedure. In addition, those respondents filing answers or other pleadings to the complaints are parties. Intervenors and answering Respondents in each proceeding are listed in Appendix A.

Also, in view of the early stage of each proceeding and the absence of any undue prejudice or delay, we find good cause to grant the late interventions of El Paso Merchant Energy, L.P. (El Paso) in Docket No. EL00-97-000, of San Diego in Docket No. EL00-104-000, of Vernon and Dynegy, et al. in Docket No. EL01-1-000, and of the Oversight Board, El Paso, Bonneville, and WAPA in Docket No. EL01-10-000.

We will reject the ISO's answer in Docket Nos. EL00-95-002 and EL00-98-002, Joint Complainant's August 18 response in EL00-97-000, and Pinnacle West's October 18 response in Docket No. EL00-104-000, as impermissible answers under Rule 213 of the Commission's Rules of Practice and Procedure. [29]

We do not act on the California Commission's Motion at this time.

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[27] San Diego Gas & Electric Co., et al., 93 FERC ¶ 61,238 (2000).

[28] 18 C.F.R. § 385.214 (2000).

[29] 18 C.F.R. § 385.213(a)(2) (2000).

Finally, the Commission has received numerous communications concerning this proceeding. Under Commission Rule 2201 (18 C.F.R. § 2201), "Off-the-Record Communications," written communications could be construed as prohibited, ex parte contacts if they involve the merits of the proceeding and do not comply with the Commission's filing and service requirements.

Because of the high level of public interest in this proceeding, however, and the numerous communications that the Commission has received and will likely continue to receive, the Commission will act under section 2201(e)(1)(i) of its Rules to deem any communication to the Commission from a person who is not a party as exempt under the Commission's ex parte rule. The Commission directs the Secretary to place all such documents in the public, decisional record and to list them on the docket sheet of this consolidated hearing proceeding.

B. Overview of Price Mitigation

1. The Fundamental Remedy

The comments and dialog at the November 9 conference underscored that there was much about the price mitigation proposed in our November 1 Order that was misunderstood. Many commenters are under the impression that we are relying on the $150 breakpoint and related pricing and reporting rules as the primary price mitigation tool. As we explain in this overview, our primary price mitigation is to eliminate undue reliance on the spot market so that price volatility in the spot markets will no longer have the ability to cause the adverse economic consequences that it has to date. In this context, the $150 breakpoint serves as a supplemental price mitigation measure. In addition to this overview, each component of that price mitigation and our answer to specific objections and comments will be discussed in subsequent portions of this order.

2. Summary of November 1 Order

In our November 1 Order, we proposed price mitigation measures for sales in the PX's Day-Ahead and Day-of markets and the ISO's Ancillary Services and Real-time energy markets (herein referred to as the spot markets). In so doing, we noted that the central cause of the exposure of California to high prices can be traced directly to a mandated over reliance on these spot markets. As we stated, between 1996 and 1999, California added about 700 MW of generation while its peak load grew by some 5,500 MW. This, coupled with reduced availability of generation from out of state and little demand responsiveness to price, leaves California's spot markets vulnerable to price spikes caused by even small suppliers who, under tight supply conditions, can affect the PX and ISO market clearing prices. The result was unprecedented cost exposure for the consumers of California.

Accordingly, we proposed a three-pronged price mitigation. First, we proposed to free the IOUs from the requirement that they sell all of their generation into and purchase all of their energy requirements from the PX. Most important, this would release the IOUs from the California Commission's requirement that nearly all of the IOUs' needs be purchased in these spot markets.

Second, we proposed that California market participants preschedule all resources and loads with the ISO and to limit their real-time energy purchases from the ISO to no more than 5 percent of their total load. We also proposed penalties on underscheduled load and removed incentives for resources to favor the real-time market . We were concerned that the real-time market can be the most volatile and that reliance on this market had reached levels which were inconsistent with proper risk management. At times, the ISO was being forced to supply a large portion of California's load at the last minute as the supplier of last resort. System operations were jeopardized as the ISO was effectively transformed from providing the imbalance services needed for reliable transmission to the supplier of last resort.

Third, we proposed to limit the use of the single price auction in these spot markets to bids at or below $150. We emphasized that, with little or no forward contracting, a significant factor causing high prices was the fact that every MW in the market is priced at the spot market clearing price. We therefore proposed that suppliers who bid above $150 be paid their as-bid costs, but not be allowed to set the clearing price. These sellers would be subject to reporting confidentially for each transaction above $150, the name of the seller, the price and amount of MWs covered by the transaction, the hour(s) covered by the transaction, and the incremental generation cost or the legitimate or verifiable opportunity costs that the seller considered in developing its bid. The PX and ISO would be subject to monthly confidential reporting for all bids (both for public and non-public utilities) in excess of $150, to include certain market data such as bid sufficiency and unit availabilities.

3. Benefits of Self Scheduling

We reaffirm in this order the central piece of our proposed price mitigation, which is the elimination of the requirement for the IOUs to sell all of their generation into and buy all of their energy needs from the PX. This requirement caused the over reliance on spot markets, which lies at the very heart of the high prices in California. By eliminating this restriction, we will release the entirety of the IOUs' 40,000 MW of peak load from the PX. In every real sense, the IOUs will be free to mitigate their own spot price exposure by meeting their requirements (under long-term contracts in the bilateral markets). Just as significantly, the IOUs will be able to use the 25,000 MW of generation which they still own or have under contract to serve their load without having to contract with anyone. [30] This places 25,000 MW of resources directly under the jurisdiction of the California Commission. Thus, the California Commission is free to price these MWs at cost or any way it sees fit for setting retail rates. IOUs will no longer be required to bid in their own resources and buy the energy back at the market clearing price. This is a comprehensive measure which will mitigate the spot market exposure of most of the peak load in California.

The IOUs will need the ability to mitigate their exposure by using their considerable portfolio of owned generation to serve their load and by contracting for the supply of the rest of their load with a balanced portfolio. While we do not in this order prescribe a particular maximum level of purchases from spot markets, or short-term purchases in the bilateral markets, we strongly urge the IOUs to move their load to long-term contracts of two years or more. While there is certainly no single right answer as to what the balance between long and short-term purchases should be, the short-term and spot markets should be used to shape a portfolio, not to define it. Instructive in this regard is that other ISO markets (e.g. NEPOOL, NYISO, and PJM) maintain less than 20 percent in the ISO spot markets.

We cannot emphasize enough that the California Commission must act decisively and immediately to eliminate the requirement for the IOUs to buy the balance of their load from the PX. [31] This is the most serious flaw in the market design created by AB1890 and the California Commission's implementing orders. Continued delay in making this fundamental change places all other aspects of our remedial plan at risk, and prolongs the dysfunction of this market. In addition it is crucial that the California Commission move quickly to provide the IOUs with approval of their forward purchases. The specter of after-the-fact disallowance for transactions other than PX purchases has certainly chilled the decision making process and continues to subject California's ratepayers to the volatility of spot prices. California is in a state of economic emergency, and there is little chance that the IOUs will rise to the task if they are not afforded certainty. [32]

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[30] In response to a data request supplied by the ISO to FERC staff investigating the Summer price spikes and supported by our analysis of FERC Form No. 1 data, the IOUs own or control, under contract, approximately 25,000 MWs of resources.

[31] We note that the California Commission has scheduled for its December 21, 2000 meeting consideration of a proposal to remove the requirement that the IOUs to purchase their power from the PX.

[32] According to Governor Davis' December 1 comments, he has also asked the California Commission to develop benchmarks to provide assurance to the IOUs regarding

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4. Functioning Forward Markets Will Be There for California

Some parties in this proceeding argue that the prices in the forward markets will be affected by last summer's spiraling spot prices and should therefore be deemed unreasonable. We do not agree. Sellers will certainly be aware that supplies of power are tight and that the IOUs are now aggressively seeking to avoid the exposure of the spot markets. Under these circumstances, as discussed below, we will be vigilant in monitoring the possible exercise of market power. However, suppliers also benefit from the stable revenue stream of forward markets and have every bit as much incentive to avoid the volatility of the spot markets as do purchasers.[33] Moreover, suppliers will bargain knowing that the spot market's size will be greatly reduced and that next summer's spot prices will therefore not be fueled by frenzied buyers whose over-reliance on last minute purchases have forced them to bid up the prices to obtain needed supply. Suppliers, of course, will be influenced by their best projection of next summer's gas and NOx prices. The cost of these vital inputs has risen steadily from about $2 MMBtu and $6/lb in 1999 to well over $50 MMBtu and nearly $50/lb now.[34] Estimates of the cost of these inputs will heavily influence forward prices more than anything else. The rise in the cost of these critical elements will inevitably affect forward prices, but this will be based on analysis and expectations for next summer, and not last summer. Therefore, as discussed later in the order, we will not mandate forward contracts at specified prices. Moving to forward markets, a buyer's willingness to pay and a seller's ability to demand high prices is greatly reduced compared to real-time. Generators have made it clear in this record that they have a strong preference for long-term markets and we emphasize that we expect them to respond accordingly. Their participation in long-term markets is crucial to mitigating prices in the near term. Of course, the long-term solution is to build generation and transmission additions.

Many pleadings argue that moving to forward markets, in and of itself, will dampen any seller's market power. We agree. However, we also recognize that the elimination of the PX buy/sell requirement will move a considerable amount of load from the spot to the forward market at one time and that some have argued that this will create yet another

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[32](...continued)
the reasonableness of their forward contracts.

[33]While suppliers clearly benefit on the upside of price volatility, the risks of price swings move in both directions. A supplier that relies exclusively on spot markets is exposed to the risk that, due to favorable weather or supply conditions, prices will be too low to cover its costs.

[34]The California Commission argues that the cost figures cited by the Commission are inaccurate. We respond to these arguments later in this order.

strong sellers' market. To address concerns about potentially unjust and unreasonable rates in the long-term markets, we will monitor prices in those markets and also adopt a benchmark that we will use as a reference point in addressing any complaints regarding the pricing of long-term contracts negotiated over the next year, after which time the sudden increase in forward demand will have subsided. In determining an appropriate benchmark, we note that the average embedded generation cost component of the IOUs' rates, which were frozen when restructuring began, was about $67.45/MWh. [35] Moreover, since the $67.45 figure reflected a 10 percent rate reduction from pre-restructuring levels, the pre-restructuring rates were about $74/MWh. In November, Duke Energy reported that it had offered to supply SDG&E's entire 3,300 MWs of load for five years at a fixed price of $60/MWh (escalated at three percent per year).[36] Since that time, gas prices have hit the $50/MMBtu level and Duke Energy is now considering a price in the $80/MWh range. We note that even this higher figure is close to the $74/MWh level of the pre-restructuring rates and is but a fraction of the current spot electricity prices. While we do not have jurisdiction over retail rates, it is our view that five-year contracts for supply around-the-clock executed at or below $74/MWh can be deemed prudent. [37]

Given the current market conditions and the rising cost of generation inputs, we believe that negotiated long-term prices that are below the levels of the pre-restructuring rates are just and reasonable. We expect that buyers may elect to negotiate above those levels to the extent they believe the particular contract or supplier brings value which suits their needs (e.g. shorter-term contracts, favorable terms and conditions, assignment of the risk of variable cost exposure, the particular characteristics of the supplier or its resource portfolio, etc.). [38] Sellers of long-term service currently have market-based rate authorization. We are not establishing a new standard for market-based prices for long-

[35] Several parties (e.g. WPTF at 24) state that the average cost of generation under the cost-based rates at the time restructuring began in 1998 was $67.45/MWh.

[36] SDG&E disputes these claims in a December 14, 2000 pleading in this proceeding.

[37] Under long-standing Supreme Court precedent, our wholesale rates must be considered just and reasonable for purposes of flow-through in retail ratemaking. See, Nantahala Power and Light Co. v. Federal Power Commission, 384 F.2d 200 (4th Cir. 1967), cert. denied, 390 U.S. 945 (1968); Mississippi Power & Light Co. v. Mississippi ex rel. Moore, 487 U.S. 354 (1988).

[38] For example, in times of increasing fuel costs, short term prices may be higher than reflected in a negotiated five year contract, while in times of decreasing fuel costs, short term prices may be lower. Also, parties may negotiate the allocation of risk that fuel prices may change and this risk allocation will be factored into the negotiated rate.

term contracts. Rather, as discussed above, we are providing an advisory benchmark to assess potential complaints regarding long-term contracts. This will assist buyers and sellers over the next year when so many MWs will be entering the forward market at one time. This advisory benchmark should not be interpreted as establishing a price floor on forward contracts, which may justify a lower per MWh price. We also believe that concerns about the availability, pricing and prudence of forward contracts may be more quickly resolved if all affected parties - - buyers, sellers and state officials - - attempt to develop a mutually agreeable plan for the initial round of forward contracts. We believe that a conference may provide the best forum to reach agreement in the short time available, and we encourage the parties to explore these types of processes.

In order to corroborate our benchmark and to adjust it if necessary, we direct all sellers with market-based rate authority to report to this Commission no later than January 2, 2001, on a confidential basis, round-the-clock long-term products in annual increments between two and five years which they are willing to offer in California. These informational reports should include price, terms and conditions, and amounts. We will also rely on this data to assess the supply and prices in the forward markets. To the extent that parties prefer, for the purposes of transparency, to report on a non-confidential basis or to post these offers on their websites, they may so advise us.

5. Restore California's Original Objective of a Small a Real-Time Market

The second facet of our proposed mitigation of spot prices, which we reaffirm today, is the elimination of chronic underscheduling. We pointed out in our November 1 Order that the ISO had been called upon to provide as much as 6,000 MW of load in real-time as the supplier of last resort. This jeopardized system operations and created a strong sellers' market and higher prices as real-time approached. As we noted, as a result of the underscheduling, the ISO was effectively transformed from supplying the balancing services needed to provide reliable transmission to becoming a market participant and administering a sizeable energy market. Our November 1 Order proposed to require that market participants preschedule their load and imposed penalties when loads in real-time exceeded more than 5 percent of an entities load. We also removed the financial incentive for generators to favor the real-time market by directing that they receive the capacity payment for replacement reserves or the energy price, but not both. In this Order we generally reaffirm our proposals on underscheduling, but with certain clarifications discussed below.

Removal of the mandatory buy/sell requirement and elimination of chronic underscheduling will directly limit the amount of load in the most volatile spot market – the real-time imbalance energy market. Just as importantly, we believe that this reform will allow the ISO to focus on the business of running the transmission system rather than a marketplace. Even at peak times, only about 2,000 MW (i.e., about 5 percent of peak load) will now be in the real-time market, down two-thirds from the prior high of 6,000 MW. This will, therefore, substantially reduce the cost exposure to buyers who now can move 4,000 MW of load into the forward markets. We again emphasize that this form of price mitigation is very effective without introducing traditional cost-of-service pricing which reflects the cost of the assets without any regard to market conditions. Some form of administratively determined price would simply dampen the supply response in the long run.

6. Limitations on the Single Price Auction

The last element of our proposed price mitigation is the $150 breakpoint above which suppliers receive their actual bids, subject to certain reporting and monitoring requirements, but would not set the clearing price. As further discussed herein, we reaffirm the use of the $150 breakpoint but only on an interim basis. We also will clarify the $150 breakpoint is not a hard price cap and, as discussed below, will provide expedited procedures for analyzing prices above $150.[39]

By establishing a $150 breakpoint and not pricing every MWh at the clearing price, spot prices will no longer be magnified. This will provide substantial relief to the buyers who remain in this market. While the breakpoint itself has received the most attention and discussion in the comments, it is not the most important of our mitigation measures. In fact, it is simply a monitoring safety net for what will be vastly reduced spot market purchases. Because load-serving utilities will move the majority of their load out of the ISO's balancing market, this ISO market will now be a residual market rather than a primary one. This is an important point because it means that only 5% of the load will remain in the ISO's balancing market and require this additional price mitigation measure. We emphasize that, by design and definition, spot markets must be allowed to reflect the price swings which capture their temporal nature. In markets such as these, which are the closest to when demand must be met, sufficient supply often manifests itself by dramatic price drops while tight supply can produce dramatic price increases. This is the nature of spot markets. Those who remain in the spot market for buying their residual load or selling their residual supply should be there in full recognition of the effects on price of last minute sales and purchases.

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[39]Many have argued that we should establish a hard cap instead of a breakpoint; however, price caps have been in effect for some time already and have not stabilized these markets. In this order, we directly address the fundamental market flaws as a means of stabilizing these markets and find that continued use of a price cap is not a necessary or appropriate element of the remedial package. We address the commenters' arguments further in later portions of this order.

As to the particular level of the breakpoint, recent gas and NOx prices are hovering at $50/MMBtu and $50/lb, respectively. [40] This would produce energy prices of between $400 - $500 for combined cycle gas facilities with heat rates between 8,000-10,000 Btu/kWh. Since gas is the marginal fuel which produces over 50 percent of the energy in California, we see good reasons not to lower the breakpoint under prevailing conditions. On the other hand, we will not raise it in the face of these higher costs. We are firmly committed to monitoring prices and to raise the breakpoint only if the goals of generation adequacy and service reliability are threatened generally. As to those commenters who suggest that we index this breakpoint, we reiterate that our primary mitigation measure is to move load and supply to longer-term forward markets. This process will be enhanced by simplicity and transparency in the spot markets. Moreover, the wide swings in spot gas prices over the last month demonstrate that indexing would result in a constantly changing breakpoint. We see no compelling reason to add the complexity of multiple breakpoints or to index a single breakpoint since this will be a small part of the market. Moreover, this particular monitoring program is interim and will be replaced by a permanent program in only four months.

7. Commitment to Ongoing Market Monitoring

We are very aware of our responsibility under the FPA to monitor markets to ensure that rates in the markets remain within a zone of reasonableness. [41] While parties have raised an array of price cap or other mitigation proposals (as discussed in detail infra), we believe our $150 breakpoint is an appropriate complement to the residual markets and will allow the markets to operate while affording purchasers a monitoring safety net. Prices for gas and NOx have risen substantially and will no doubt be reflected in higher prices even

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[40] Average California regional gas prices peaked in the range of $7-$12 for the week ending November 17, 2000, National Gas Intelligence Weekly Gas Price Index, Vol. 13, No. 28. More recent prices have reached the $50 level. NOx costs for the San Diego area remain near $50/lb, Cantor Fitzgerald Market Index, November 22, 2000.

[41] See, e.g., Farmers Union Central Exchange, Inc. v. FERC, 734 F.2d 1486, 1509 (D.C. Cir. 1984) (Farmers Union) ("FERC's methodology . . . exposes a range of permissible prices that would exceed the 'zone of reasonableness' by definition, unless competition in the oil pipeline market drives the actual prices back down into the zone. But nothing in the regulatory scheme itself acts as a monitor to see if this occurs or to check rates if it does not. That is the fundamental flaw in the Commission's scheme."); Environmental Action v. FERC, 996 F.2d 401, 410 (D.C. Cir. 1993) (Finding a flexible pricing approach acceptable, the court noted that the Commission "ordered disclosure of all transaction prices, thus putting WSPP members on notice that their transactions would be monitored.").

with our market reforms in place. Our monitoring will give purchasers the assurance that these cost factors have contributed to the higher spot prices rather than the exercise of market power. In implementing our monitoring, we will rely on several indicators of potential market power, including: the outage rates of the seller's resources, the failure to bid unsold MWs into the ISO's real-time market, and variations in bidding patterns for the same or similar resources (e.g. bidding large blocks of capacity at a low price and a small amount of capacity at a high power price for the purpose of setting the market clearing price for the entire amount). While the presence of one or more of these factors will not necessarily result in price mitigation, it will serve as a clear signal for careful review. We fully realize that sellers may bid above their marginal cost in times of scarcity. We intend to close our review of as-bid transactions within 60 days after the transaction report is filed with us. Absent notification by the Commission or its staff (e.g., a data request, order, or other written notification from the Commission) within 60 days all transactions will be considered final and will not be mitigated. If the Commission does not issue some form of written notification within 60 days, refund liability will automatically end. If notification is received, refund liability will continue until the review is terminated and a final Commission order or staff letter is issued. This, in conjunction with the fact that bids will not be mitigated if they simply reflect higher costs, should provide both flexibility and finality to the marketplace. It will also provide customers protection by providing early review of as-bid prices that may not be just and reasonable and prompt rate relief for prices that are mitigated..

We also intend to perform this monitoring for only an interim period until a more comprehensive approach can be developed. We therefore direct the Director of our Division of Energy Markets in the Office of Markets, Tariffs, and Rates to convene a technical conference as suggested by the ISO. The Conference will be held no later than January 25, 2001. The purpose of the conference will be to develop a comprehensive and systematic monitoring and mitigation program which incorporates appropriate thresholds and screens and specific mitigation measures if those thresholds and screens are breached. In this regard, we believe that well-defined and timely price mitigation should eliminate the need for after the fact reviews and introduce price stability and certainty in the ISO markets. We expect the input of all interested market participants and are particularly interested in the views and expertise of the ISO's market monitoring unit both in assisting our staff in developing this program and in implementing it. We direct our staff to submit a proposed plan to us no later than March 1, 2001, so that the Commission can notice the plan, order any needed modifications and implement the plan by May 1, 2001. This is the date on which we will terminate the PX's rate schedules (as discussed below) and, therefore, all monitoring of the PX will cease on that date. The Commission's approved permanent monitoring will replace our interim monitoring for the ISO's markets on May 1, 2001.

8. There Are No Easy Answers

The pleadings clearly demonstrate that there is no single right answer to solving this market's problems. Many buyers in this market ask us to impose some form of price control (e.g., a simple cap; a load differentiated cap). We carefully considered these proposals and recognize that they have the appeal of potentially lowering prices in the very near term. However, the devices are arbitrary and have unforeseeable economic consequences, often to the detriment of consumers on the electric system.[42] In a practical sense, they are a form of cost based regulation and lowering prices in the spot market will again create biases between markets and, further, not provide sufficient incentives for building the new generation resources that are critical for California. Every time we intervene in one market, we affect other markets and prevent, rather than support, the development of efficient, competitive bulk power markets.

Some (e.g., Department of Energy) have requested that we force generators to sell into the ISO's market and bid in at their running costs. While this proposal is appealing at first blush, because it seems to use market mechanisms (i.e., marginal cost pricing) rather than traditional asset-based pricing, this is simply another form of cost based regulation which attempts to arrive at the cost that a properly functioning market would produce. However, any attempt to simulate how this market would work under perfect conditions, such as the absence of scarcity, will not induce supply entry. Moreover, it can create pricing distortions in the forward markets at a time when it is critical that forward markets develop and mature and take their place as an unbiased option for all market participants. We have elected to proceed by accommodating the economic operational changes that have already occurred in the market, with an approach of letting the market set the prices in response to changing conditions and growing demand, subject to appropriately tailored mitigation because it has the fewest flaws of any of the approaches presented on the record. We cannot afford to stymie entry and we therefore chose to err on the side of relying on the market to set the scarcity price subject to our monitoring rather than depressing prices and running the risk that much needed supply goes elsewhere. We will gain experience with both the interim and permanent monitoring programs and will make needed changes as we go forward.

9. Justness and Reasonableness of Rates

In our November 1 Order we found that the electric market structure and market rules for wholesale sales of electric energy in California are seriously flawed and that these structures and rules, in conjunction with an imbalance of supply and demand in California,

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[42] Indeed, the existing purchase price cap led to a severe reduction of bids into the ISO's markets which, in turn, seriously threatened reliability by forcing the ISO to scramble at the last minute to obtain needed supplies.

have caused, and continue to have the potential to cause, unjust and unreasonable rates for short-term energy (Day-Ahead, Day-of, Ancillary Services and real-time energy sales) under certain conditions. We stated that while the record did not support findings of specific exercises of market power in these spot markets, and while we were not able to reach definite conclusions about the actions of individual sellers, there was clear evidence that the California market structure and rules provide the opportunity for sellers to exercise market power when supply is tight and can result in unjust and unreasonable rates under the FPA.

Several parties have challenged these findings or have sought clarification of them. Dynegy argues that the Commission erred in finding that the rates in California were unjust and unreasonable. Dynegy asserts that the Commission should look at the entire two and one-half year period since the California market opened and the approximately $11 billion in net benefits that consumers got over that period. It further argues that any remaining price increase is due to scarcity, not the abuse of market power, and justifies the price increases at issue. Similarly, Reliant asserts that the higher market prices in California were attributable to market fundamentals and are not unjust and unreasonable. Enron asks the Commission to clarify that it has not found that the actual rates charged by Enron (and other market participants) during the summer of 2000 were unjust and unreasonable, and that the Commission reject the use of short-run marginal costs for measuring market power. Calpine also argues that the Commission has made no findings in these proceedings that any individual market participant's rates were unjust and unreasonable. Likewise, Duke asserts that the Commission must confirm that it has not found that the overall level of summer 2000 prices were unjust and unreasonable, and that the Commission should reconfirm that there is no evidence that any improper exercise of market power caused the high prices.

As an initial matter, we note that the November 1 Order did not find that all rates, at all times, were unjust and unreasonable in these spot markets. Nor did we make findings about whether particular rates charged by specific sellers during the summer of 2000 were unjust and unreasonable or that any individual sellers exercised or abused market power. Further, although the record has now been supplemented with additional information and evidence, nothing has been presented that would cause us to change the findings in the November 1 Order or that would permit us to further refine the findings that were made.

We have been faced in this case with the difficult question of what makes a market-based rate unjust and unreasonable. There is no precise legal formulation for setting a just and reasonable rate and no precise bright line for when a rate becomes unjust and unreasonable. Under long-standing Supreme Court case law, rates must fall within a zone of reasonableness where the rates are neither so low as to be "less than compensatory" nor so high as to be "excessive" to consumers. [43] While high prices in and of themselves do not make a rate unjust and unreasonable (because, for instance, underlying production prices may be high), if over time rates do not behave as expected in a competitive market, the Commission must step in to correct the situation. [44] Further, while exercises of market power may cause a rate to be unjust and unreasonable, in the circumstances here, independent of any conclusive showing of a specific abuse of market power, a variety of factors have converged to drastically skew wholesale prices under certain conditions: significant over-reliance on spot markets which by their very nature can produce dramatic price increases when supply is tight; significant increases in load combined with lack of new facilities as well as reduced availability of supply from out of state; chronic underscheduling; and lack of demand responsiveness to price. There is not sufficient evidence on this record to find that particular sellers have exercised market power or that they have violated Commission-approved market rules. Moreover, going forward, we have no assurance that rates will not be excessive relative to the benchmarks of producer costs or competitive market prices, due to the circumstances listed above. Therefore, we reaffirm our findings that unjust and unreasonable rates were charged and could continue to be charged unless remedies are implemented.

In light of the circumstances presented by California markets, the Commission will actively monitor for exercises of market power as well as other factors that may lead to unjust and unreasonable wholesale prices. As discussed in the mitigation section, there are several indicators of potential market power which we will closely scrutinize for future sales, including: the outage rates of the seller's resources, the failure to bid unsold MWs into the ISO's real-time market, and variations in bidding patterns for the same or similar resources. Also, we have ordered the development of a comprehensive and systematic monitoring and mitigation program for the spot markets which incorporates appropriate thresholds and screens and specific mitigation measures if those thresholds and screens are breached, to be in place by May 1, 2001. In addition, we have established a benchmark for just and reasonable long-term prices and will monitor the supply and prices for long-term products.

In response to Dynegy, we agree that in analyzing the reasonableness of rates in a particular market we cannot look at prices based on an isolated time period, but rather must look at a representative time period. We further agree that we need to distinguish scarcity

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[43] See, e.g., Farmers Union Central Exchange, Inc., 734 F.2d 1486, 1502 (D.C. Cir. 1984), cert. denied, 469 U.S. 1034 (1984) (Farmers Union); FPC v. Hope Natural Gas Company, 320 U.S. 591, 602-03 (1944).

[44] See, e.g., Farmers Union, 734 F.2d at 1509; Environmental Action v. FERC, 996 F.2d 401, 410 (D.C. Cir. 1993) (Environmental Action).

rents from exercises of market power; however, we disagree that, absent exercise of market power, prices are necessarily just and reasonable. Our analysis must be, as discussed above, based on a determination of whether the rate falls within a zone of reasonableness.

C. Requirement to Sell Into and Buy From the PX

The cornerstone of our price mitigation program, our proposal to eliminate the PX buy/sell requirement, received overwhelming support from parties with a broad spectrum of interests. For example, the California Legislature (at 3) states that: "We applaud the Commission's desire to see California move away from spot market rates and towards a portfolio that strikes a balance of long-and short-term contracts, with the aim of both stable costs and reasonable costs." The one notable exception is the California Commission (at 41), which states that: " [the Commission's] elimination of its 'Buy' requirement does not eliminate the California Commission 'Buy' requirement." The California Commission emphasizes that its "buy" requirement will remain in place until the California Commission removes it. [45] We take this opportunity to emphasize that eliminating any mandated reliance on the spot market represents the single most important aspect of wholesale market reform and is one of the most critical components of all the immediate market reforms necessary to correct the pricing problems in California electric markets and provide long-term protection of customers. According to the California Commission, because the state has an appropriate role in crafting long-term solutions with respect to the elimination of the buy/sell requirement, we should modify our proposal. We disagree. Immediate action is crucial to ensure that the "Buy" restrictions imposed by the California Commission do not undermine interstate wholesale power markets.

As we have previously acknowledged, the California Commission is correct that it has authority over the prudence of an IOU's procurement practices for providing retail service. However, we conclude that the current PX buy/sell requirement produces an unworkable spot energy exchange that does not operate as a market. Rather, the mandatory participation requirement of regulators is producing rates that are not just and reasonable during certain periods. Further, although we are removing the mandatory buy/sell requirement from the PX tariff under our jurisdiction, we must recognize that this action alone will not serve to rectify the situation. As long as the California Commission continues to require (either directly or indirectly) the IOUs to sell or purchase the bulk of their needs from the PX, volatile short-term energy prices will continue to engulf the market. Unless this restriction is removed by the California Commission, the wholesale

[45] A separate statement of Commissioners Duque, Neeper and Bilas strongly supports removing this restriction noting that they have previously voted to end the PX monopoly.

markets under our jurisdiction will continue to produce prices which are unjust and unreasonable during certain periods. In light of our statutory obligations to ensure just and reasonable wholesale rates, we therefore further conclude that it is necessary to take the unusual step of terminating the PX's wholesale tariffs which would enable it to continue to operate as a mandatory exchange. We do not take this step lightly, particularly since we have concluded that buyers need more, not fewer, supply choices to achieve adequate risk management and lower prices. However, it is only by eliminating the PX's exclusive mandatory exchange that we can assure that prices in California wholesale markets will be just and reasonable.

We recognize that California Governor Davis' December 1, 2000 letter filed in this proceeding states that the California Commission has been directed to expeditiously develop benchmarks to assure the reasonableness of forward contracts by the California IOUs without unfairly second guessing these decisions in later years. It is possible that we may be able to re-institute the PX tariffs at a later time, depending upon the outcome of the California Commission's efforts or other changed circumstances. [46] In the meantime, however, to ensure that the market reforms proceed in a timely manner, we will terminate the PX rate schedules effective as of the close of the April 30, 2001, trading day. [47] The interim time period should allow parties sufficient time to negotiate and finalize alternative arrangements and to prepare a more balanced portfolio. We believe that a longer time period would merely protract negotiations in the critical summer period.

Many parties complain that the California Commission's current prudence review standard frustrates or impedes the negotiation process for longer term supply arrangements. For example, Duke Energy has offered to supply the full native load requirements of SDG&E for a period of five years at a fixed price of $60.00/MWh (escalated at 3 percent per year). Duke Energy and others have previously offered to supply energy under long-term fixed-price contracts at less than the IOUs' embedded cost rates. We re-emphasize that the California Commission has been directed by the Governor to develop benchmarks to help address these prudence review concerns.

The California restructured market is the only one that began without some form of buy-back contract with the new operators of the divested generating facilities. In other markets, such contracts are an integral component of the divestiture transaction and are

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[46]As we noted in the November 1 Order, the PX is free to reconstitute itself as an independent exchange with no regulatory mandated products and offer the services needed by market participants.

[47]PX FERC Electric Tariff, Third Revised Volume No. 1 and PX Trading Services Second Revised Rate Schedule FERC No. 1.

intended to protect customers from spot price volatility during the early years of the market. As service under these initial contracts declines over time, parties are free to negotiate mutually agreeable forward contracts to continue this hedging strategy.

The California Commission (at 5 and 21) states that the Commission should address the reasonableness of forward prices by mandating medium-term forward contracts at regulated prices, modeled on "vesting contracts" used in New York (i.e., utilities bought back power from the new owners of the divested units under long-term contracts). This proposal is simply not workable because the New York restructuring model, as discussed above, included the buy-back terms and conditions as an integral component of the divestiture transaction (and was therefore reflected in the negotiated purchase price) and the two components cannot be decoupled as suggested by the California Commission. The fact that parties do not have recourse to buy-back arrangements is due to the buy/sell spot market restructuring model that California initiated. The generation asset sales transactions cannot be unraveled after-the-fact to impose an obligation on the new generation owner that was not reflected in the agreed-upon sales price.

We are mindful that our elimination of the PX buy/sell requirement will move a considerable amount of load into the forward markets all at one time. While we have not mandated a price for long-term sales, we are establishing, effective for one year an advisory benchmark for a five-year product which buyers and sellers can consider as instructive for evaluating the reasonableness of long-term prices and which we will consider in addressing any complaints about prices in the long-term markets.[48] In light of the current market conditions, and the rising cost of generation inputs, the prices in effect when restructuring began constitute a reasonable benchmark.

According to Duke Energy and others, if the Commission's reforms are implemented and linked with state policies that do not favor spot purchases over forward contracts a wide array of bilateral forward contracts will be negotiated. State Senator Bill Morrow states that urging greater reliance on forward contracts will have little effect unless the utility purchasers have some safety from "reasonableness review" by the California Commission.

At present, the California Commission uses the PX as an index of reasonable purchased power costs. We agree with Duke Energy that the presumptive reasonableness of the PX prices causes the IOUs to favor spot purchases and avoid long-term purchases. When state policies provide that the only "safe harbor" from prudence reviews is in spot markets, the inevitable result will be excessive reliance on spot markets. Our elimination of the PX rate schedules will remove the medium for favoring spot sales and should

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[48]The specifics of the advisory benchmark are described in the overview, Section B.

provide the IOUs with every incentive to purchase the most cost-effective portfolio rather than to simply purchase in a PX. That portfolio will no longer be skewed by a favored and mandatory spot market. We have established our advisory benchmark so that sellers and purchasers can have a reference point for the reasonableness of their long-term contracts during negotiations. In order for the California consumers to see the benefits of long-term contracts, the California Commission must quickly provide the IOUs with timely approval of their long-term purchases using policies that apply evenly to short and long-term contracts. While the Commission can only encourage such reforms, progress in eliminating artificial barriers to forward contracting are essential to stabilizing California's wholesale markets..

1. Self Supplying IOU Load

In our proposed order, we noted that while the IOUs have divested their fossil fired generation, they still own a substantial amount of low cost hydro and nuclear generation and purchase power contracts (approximately 25,000 MW). [49] In this regard we stated the following:

> Without this buy/sell restriction on wholesale trades, the IOUs are free to pursue a portfolio of long-and short-term resources and access whatever wholesale markets are suited to meeting the needs of their retail customers (including bilateral markets, the PX, and others such as Automated Power Exchange, Inc.) or by providing power from their own resources to serve their own load and self provide the necessary ancillary services. [50]

At present, the IOUs still own about 25,000 MW of resources. Under the current market structure, the IOUs are required to sell these low cost resources into the spot market and buy back the same amount of power at the market clearing price. As we said in the November 1 Order, by eliminating the buy/sell requirement the IOUs will be able to provide power from their own resources to serve their own load and self provide the necessary ancillary services. This proposed market reform, which we reaffirm here, is not intended to change the current use of these resources, but simply addresses the spiraling costs caused by the current market.

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[49] As noted in the November 1 Order, the IOUs own nuclear and hydro generation whose variable operating costs are approximately $16/MWh and no fuel costs for hydro. 93 FERC at 61,361, n. 51.

[50] Id. at 61,360-61.

We conclude that it is essential for the IOUs to cease selling and repurchasing their own generation at spot prices. The best way to mitigate cost exposure is for the IOUs to cease selling and repurchasing what they already produce. Effective on the date of this order, the IOUs are no longer authorized to sell their resources into the PX.

By providing power and energy from their own resources to serve their retail load, the IOUs will no longer be treating their own generation as a wholesale sale subject to our jurisdiction. Rather, the IOUs' approximately 25,000 MW of resources will revert to being subject to the state's retail ratemaking authority instead of the Commission's ratemaking authority (except when used to make sales for resale). In simplest terms, the Commission has effectively "de-federalized" this portion of the market effective as of the date of this order . Contrary to the scheme of AB1890, [51] this market reform will immediately reduce by approximately 60 percent the IOUs' exposure to the spot market during peak periods. During most off-peak periods the IOUs will be able to self supply most, if not all, of their requirements and almost entirely eliminate their dependence on the spot markets. [52] As previously discussed, this will place 25,000 MW of resources under the jurisdiction of the California Commission that it can price at cost-based rates, if it so chooses. However, until the IOUs execute long-term contracts, they will be residual buyers for the remainder of their requirements in the spot markets. To the extent the IOUs' resources exceed their load at various times, they are free to sell any surplus at wholesale, pursuant to their Commission-filed rate schedules. This market reform received little attention in the comments, with the notable exception of the comments filed by the California Commission.

2. California Commission Comments

The California Commission (at 20) recognizes that PG&E and SoCal Edison have retained substantial hydroelectric, nuclear and QF portfolios and SDG&E has rights to a share of the output of the San Onofre Nuclear Generating Station, plus purchase power contracts. Under the current buy/sell requirement, these resources are bid into the market as price takers (i.e., at zero cost) to ensure their dispatch. According to the California

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[51] AB 1890 was the legislation effecting electricity restructuring, signed by Governor Wilson on September 23, 1996, California Statutes 1996, Chapter 854 (Restructuring Legislation or AB 1890).

[52] For example, the load in the PX Day-Ahead market (for delivery on December 12, 2000) was below 22,700 MW. However, the energy cost for the day was over $100 million. Most if not all of the IOUs' load could have been supplied from their own resources, and this purchase power expense could have been avoided by eliminating the buy/sell requirement.

Commission, revenues from these resources were substantial last summer, as utility-owned generation received the high market clearing prices. Finally, these revenues serve to sharply reduce the IOUs' exposure to high market prices.

Inasmuch as the California Commission's comments support perpetuating the current market design, which contributed to the abnormal price volatility last summer, we find their position disturbing and contrary to the interests of retail ratepayers. The IOUs are both buyers and sellers. The prices the IOUs pay for buying back their own resources through the PX serve simply to value those resources for stranded cost purposes. As long as the IOUs pay less than the frozen retail rates, they can use the difference to write off stranded costs. This entire formula breaks down if the IOUs buy back their MWs at more than what they can charge through retail rates. This is exactly what happened last summer. Moreover, the process is unnecessary even for stranded costs purposes because the IOUs have now valued or recovered all of their stranded costs. [53]

The California Commission has not justified continuation of market rules requiring the IOUs to buy and sell power exclusively through the PX, other than stating that state law (Assembly Bill 2866) prohibits the California Commission prior to June 1, 2001 from removing this restriction. In light of the profound distorting effect this restriction has on the wholesale markets and the financial integrity of the IOUs, we have no choice but to eliminate this restriction as of the date of this order. Any benefits the IOUs receive from selling solely into the spot markets are far outweighed by the financial harm of buying solely in the same spot markets, since the IOUs are net buyers of power. While the California Commission has relied on PX prices in calculating the IOUs' stranded costs, as we stated in the November 1 Order, these stranded costs have now been recovered or valued. [54]

D. Underscheduling of Load and Resources

In order to reliably operate the transmission system, the ISO must continually balance generation and load. There is general agreement that the ISO's real-time balancing market should be limited to fine-tuning supply and demand and that the excessive amount of energy regularly being transacted in this market is inappropriate. The ISO imbalance

[53] The conflicting incentives where the IOUs are both buyers and sellers also occurred in the QF program. Our experience there is instructive in this regard. The IOUs had the irreconcilable goals of needing to minimize QF costs as buyers and maximizing QF revenues as partial owners of QFs.

[54] Duke Energy (at 7) notes that, to date, stranded cost recovery estimates show PG&E collected \$8.3 billion and SoCal Edison collected \$9.3 billion.

market was intended to perform a reliability function and not be used as an energy exchange. As noted in our prior order, managing a significant amount of load and generation in real-time raises reliability concerns. Creating incentives for load and suppliers to bid and schedule in the forward markets will help reliability and promote more competitive markets. As a result, our order attempted to address this problem with a balanced approach to encourage both load and supply to schedule prior to real-time.

The Commission proposed to require market participants to schedule 95 percent of their loads prior to real-time as well as to make a number of interrelated modifications to address the underscheduling problem. The Commission proposed: (1) eliminating different price caps in the ISO imbalance market and the PX exchange markets; (2) imposing a penalty charge (two times the cost of energy not to exceed $100/MWH) for deviations in scheduling in excess of five percent of an entity's total hourly load requirements;[55] (3) disbursing of penalty revenues to the loads that scheduled accurately during the trading hour in which the charges were incurred; and (4) limiting suppliers who participate in the real-time market to either a capacity payment for replacement reserves or energy payments, but not both. The order explained that elimination of the PX buy/sell requirement and allowing the ISO to procure resources on a more forward basis would also address the problem of underscheduling. Our hope is that implementing these comprehensive market reforms will greatly reduce the application of the underscheduling penalty.

Virtually all commenters agree with the Commission's general approach to the underscheduling problem. Various commenters note that underscheduling is a symptom of many of the other market flaws. For example, SoCal (at 46 - 47) notes that because the Commission quite correctly addressed all of these flaws the underscheduling problem may now largely subside on its own without the need of a penalty provision. PG&E (at 42) believes that if generators are obligated to sell to load-serving entities in a forward market the underscheduling problem should disappear and obviate the need for a penalty. SMUD (at 26) made similar comments. While there is general agreement on this issue, several specific areas warrant further discussion and clarification as discussed below.

1. The Proposed Five Percent Deadband

a. Comments

Several parties suggest that the deadband should be larger than five percent (e.g., So Cal suggests 9 percent (at 48); Reliant (at 29) suggests 10-15 percent; SMUD (at 27) suggests 10 percent with no penalty for force majeure-type conditions.) SoCal Edison said

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[55]We clarify that the hourly energy cost calculation will include any Out-of-Market purchases for that trading hour.

that the ISO's preliminary system load forecast projection made two days in advance of the trading day is off by 4.9 percent and for this reason we should enlarge the deadband.

Several other parties (e.g., AES NewEnergy, Inc.) request that the deadband be relaxed for small load serving entities such as new Energy Service Providers (ESPs) that have much less diverse loads than the IOUs. [56] They argue that without some relief they will be unable to enter the market, which will ultimately undermine the goal of developing a robust retail market. Southern Cities recommends a minimum 2 MW allowance (at 6) and a substantially higher penalty than $100/MWH (at 7). The ISO (at 20) recommends that the Commission relax the provision for small entities so that the penalty applies to the greater of 10MW or 5 percent of the shortfall in scheduling.

b. Commission Determination

Load which could have been anticipated and therefore scheduled should not be supplied through the ISO's real-time imbalance market in light of the current reliability problems that exist in California. We believe that no party has supported a real-time imbalance market greater than the 5 percent maximum amount that the ISO intended to balance. With larger deadbands the system operators will be forced to continue to run a spot market for energy and not just balance the system. However, we agree that exceptions for small ESPs (that will serve load previously supplied by the host utility) can be accommodated without greatly expanding this market. In order to encourage entry for alternative ESPs and to accommodate the lack of real-time metering data we will allow a minimum 10 MW deviation for application of an underscheduling penalty. With this modification the penalty will apply to the greater of 10 MW or 5 percent of the underscheduled amount. In other words, the five percent deviation will apply to load of 200 MW or greater. Small entities with scheduling deviations within the 10 MW amount will not be assessed a penalty and will be considered as having scheduled accurately for penalty revenue distribution. This modification for small entities should not significantly expand the ISO's balancing function.

[56] Enron alternatively suggests that the 95 percent scheduling rule could be limited to underscheduling of load only as another way for small ESPs to accommodate uncertainty in their load forecasts. Southern Cities are also concerned if forecasts are higher than actual loads. Similarly, New West Energy believes that the penalty should not apply to scheduling deviations resulting from demand responsiveness programs. Enron also requests clarification that the calculation is based on the entire load of the ESP. We clarify that the penalty applies to underscheduling only and it is based on the entire load of the market participant.

With respect to SoCal Edison, which cites the ISO two day-ahead preliminary load projection, we note that this comparison is inaccurate. This projection is generally a worst case projection and is therefore usually higher than actual load (e.g., if weather conditions are not actually as severe as projected). Implementation of interruptible load programs can also cause the projections to be higher than actual system loads. In summary, the ISO projections are not generally analogous to an underscheduling error.

Further, we do not believe that modification of the deadband is necessary due to operational concerns. We will not expand the deadband by adopting any of the alternatives that have been suggested. A proposal of a 10 percent deadband would translate into a market of well over 4,000 MW on a peak day. This level places too much of a burden on the ISO to procure needed resources even with our directing the ISO to contract on a more forward basis. Simply put, we will not encourage a greater burden of service on the ultimate provider of last resort -- the ISO, for energy procurement at the last minute.

Under the remedies included in our prior order, we encouraged the IOUs to participate fully in the forward markets in order to procure a more balanced portfolio as opposed to the current excessive reliance on the spot markets. Not only will this approach to procuring resources reduce price volatility but it should also reduce the need for procurement and scheduling decisions near real-time.

2. Generation Penalty Proposals

a. Comments

Various commenters argue that a penalty provision should apply to generation as well as load. MWD (at 7) proposes a penalty on generators with exceptions for small u units (smaller than 50 MW), and renewable resources (wind, solar, and run of the river hydroelectric generation). Independent Energy Producers (at 8). SMUD (at 29) is concerned that generators may not bid their remaining available capacity into the ISO imbalance market. SMUD argues that such generators must provide the ISO and the Commission with relevant data that demonstrates that their bidding behavior was due to real operating conditions and that penalties should be assessed when withholding is actually proven.

b. Commission Determination

We believe that the market changes we adopt today should make the real-time market less desirable for load-serving entities and generation unit owners relative to the available forward markets and the spot markets. In addition to the penalty on load, the proposed order removed the double payment feature for generation that is bid in the real-time imbalance market. Under the current market rules, generators are paid the

Replacement Reserve price and the real-time energy price for imbalance energy. By eliminating the double payment, suppliers no longer have the economic incentive to wait for the real-time market to sell power .

Other than removing the double payment feature, no workable penalty mechanism applicable to generation has been proposed. All the proposals include exceptions for various types of generation. The proposals also illustrate the complexity in determining which generators or types of generators will be assessed a penalty and when a penalty will be triggered. Currently suppliers that are unable to meet scheduled obligations are required to pay the cost of replacement energy purchased in the real-time balancing market. To avoid this result, suppliers may, for example, reserve a certain amount of capacity to self supply in the event of a contingency. [57]

Finally, as the Energy Producers and Cogen Association (at 16) note, a long-term goal should be the establishment of a structure that would facilitate the trading of hourly imbalances among Scheduling Coordinators if the system, as a whole, is in balance. While we would prefer that entities be able to trade imbalances this is not currently an option because positive imbalances do not exist at the level to alleviate the negative imbalances. As the system normalizes and approaches an equilibrium (with equal amounts of overscheduling and underscheduling), we expect that an imbalance trading program will be instituted.

3. ISO Implementation

In order to implement the proposed market revisions, the ISO states that it must modify its Scheduling Infastructure and Applications software as well as its Settlement/Billing System. The ISO explains that implementing the automated billing changes is the most onerous and could take as long as four months to implement. Alternatively, the ISO suggests an approach using blends of automated and manual processes which could be accomplished by January 1, 2001. The ISO cautions that this approach could be extremely time-consuming due to the frequent rerunning of settlements that are caused by changes in meter data.

In order to accommodate the concerns raised by the ISO and the need to implement the needed market revisions, we direct the ISO to implement a blended automated/manual approach. We also suggest that, in order to simplify the settlement process, the ISO is

[57] Parties have proposed alternative penalty provisions (e.g. graduated penalties), which we have not adopted. We note that as the ISO will have to integrate a number of interrelated market reforms under this order. As the ISO gains operating experience it is free to propose a modification to penalty procedures.

authorized to temporarily institute estimated billing procedures. Under this billing method, simultaneous manual billing re-runs can be avoided until the automated system is operational. Disputed imbalances in billings and payments can be placed in temporary escrow accounts prior to final billings. We direct the ISO to have its automated billing procedure in place by May 1, 2001.

4. Conclusion

Accordingly, we will require amendments to the ISO Tariff to implement the changes proposed in the November 1 Order as modified above. The ISO is directed to submit a compliance filing making these changes within 15 days of the date of this order.

E. Level of Breakpoint

1. Background

In the November 1 Order, we proposed to implement a temporary modification to the single price auctions of the PX and ISO. We proposed that, effective 60 days from the date of the November 1 Order, for all short-term markets operated by the PX and ISO (including the Replacement Reserve Market), the single price auctions be used for all sale offers at or below $150. The single market clearing price would be used for the amount of load which clears at or below this amount in the auctions. If an auction does not clear at or below the $150 bid level, suppliers who bid above $150 would be paid their as-bid price for the quantity that they bid.

In addition, we proposed to condition sellers' market-based rate authority by requiring each seller to file on a weekly basis each transaction in the ISO and PX spot markets that exceed $150. All transactions for the prior week would be filed on a confidential basis with the Commission's Division of Energy Markets. We specified that the market data to be included in the report should include the name of the seller, the price and amount of MWs covered by the transaction, the hour(s) covered by the transaction and the incremental generation cost. We also directed the seller to identify legitimate opportunity costs that are known and verifiable that the seller considered in developing its bid. We explained that the data would be used to monitor prices in order to detect potential exercises of market power or otherwise non-competitive market prices and to adjust transaction prices, if necessary to establish just and reasonable rates. [58]

2. Comments

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[58]We imposed a similar reporting requirement on the PX and ISO; however, they would file their reports, including unit availability data, on a monthly basis.

In general, commenters oppose the Commission's price mitigation proposal. Commenters either argue that the $150 breakpoint is too high or too low, that the breakpoint will act as a hard-cap or no cap at all, and the accompanying reporting requirements (supported with opportunity costs pricing) will permit unfettered prices or drive sellers from the market. In addition, commenters argue that the as-bid pricing requirement will increase prices because sellers will submit strategic bids to capture anticipated prices. On the other hand supporters of as-bid pricing argue that it makes no sense to pay people more money than they bid.

The three IOUs argue that the Commission should either impose cost-based pricing rules or at a minimum put in place the load differentiated bid cap approved by the ISO Board on October 26, 2000. [59] They argue that the $150 breakpoint [60] will do nothing to mitigate market power and the resulting high prices faced by California consumers. They contend that the $150 value is far higher than needed to attract investment in new generation, that the figure is higher than the price that a properly functioning market would expect during most system conditions, and most importantly, the proposed enforcement mechanism is so flawed that the breakpoint is unlikely to discipline prices at all. PG&E and SoCal argue that bids will cluster at or below the $150 price limit during low and intermediate load periods because sellers will construe that level to be a safe harbor under which the Commission will not monitor for market power abuse. In addition, they assert that paying sellers their as-bid price without any constraint will send prices soaring. The reporting requirements on entities such as power marketers who do not have incremental generation costs to report will leave them reporting either meaningless opportunity costs or the actual cost of their purchase price which could be wildly inflated after the power has changed hands several times. [61] Moreover, they argue that the reporting requirements will be kept secret from market participants with no timetable for resolution of the Commission's review process.

DOE is concerned that the $150 breakpoint may not produce just and reasonable rates. While still retaining the single price auction, DOE recommends that the Commission require all existing generation to only bid its marginal cost. However, DOE would exempt generation placed in service after the date of the order from the requirement

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[59]PG&E at 26-40, SoCal Edison at 7-27, and SDG&E at 12-14.

[60]Some of the commenters refer to the breakpoint as a "soft cap" or a "hard cap". For purposes of clarity, we will continue to employ the phrase breakpoint.

[61]IEP also requests clarification on how opportunity cost standards will be applied to power marketers. IEP at 24.

to bid its marginal cost, though the new generation would not be allowed to set the market clearing price. [62]

Consumer groups such as the California Retailers Association, the California Small Business Association and the California Small Business Roundtable argue that the breakpoint will result in no effective cap. TURN/UCAN continue to support the load differentiated price cap that was approved by the ISO Board. They argue that the load differentiated price cap is not complex and anyone with a pocket calculator and a copy of the Wall Street Journal could perform the calculation in minutes. [63] TURN/UCAN argue that in justifying as-bid prices with opportunity costs, absent a WSCC-wide cap, it will only take one reported transaction in the WSCC to negate the cap.

The California Commission, the California Legislature, and the CEOB also argue that the breakpoint will not restrict prices. [64] They also support some form of cost-based pricing either by requiring sellers to offer medium-term mandatory contracts at FERC-regulated rates or a load differentiated bid cap. The CEOB also requests that the Commission impose a WSCC region-wide bid cap that is set below the current ISO cap of $250.

The ISO, the PX, and the Market Monitoring Committee (MMC) of the PX have serious concerns that the Commission's price mitigation measures will have several untoward results. [65] The PX and its MMC note that the breakpoint only applies to the ISO and PX markets; therefore, sellers will flee these markets to avoid the reporting requirements. The PX requests that the Commission impose the price mitigation on all near-term trading venues, including brokers, [66] electronic bulletin boards, other exchanges and bilateral transactions. The ISO contends that the $150 breakpoint is too generous for base-load units and if history is a guide, prices will hover at that level for more hours than marginal costs would justify. The ISO also argues that tying as-bid prices to opportunity costs will greatly increase prices because of the effects of a regional uncapped market and the likelihood that transactions will leave California only to return daisy-chained or as out-of-market calls. The ISO also believes that the blending of supply prices under the bifurcated market will mute marginal cost signals needed to induce supply and demand

[62] DOE at 6-7.

[63] TURN/UCAN at 18.

[64] California Commission at 15-20, California Legislature at 5, and CEOB at 21-26.

[65] ISO at 8-17, PX at 30-32, MMC at 3-4.

[66] We note that brokering is not a jurisdictional transaction.

responsiveness programs. [67] The ISO is also concerned that the Commission's price mitigation measures may actually exacerbate underscheduling depending upon how high prices are relative to the breakpoint price and the real-time penalty for underscheduled load. The ISO proposes two forms of price mitigation that involve requiring sellers to offer forward contracts with safe harbor benchmark prices.

Both the ISO and PX raise concerns regarding difficulties that may arise in implementing the Commission's price mitigation measure. If sellers use the "as bid" alternative, the ISO and PX will have to immediately record bid-specific information for each bid submitted above the $150/MWh breakpoint. According to the ISO, this information can be implemented using blends of automated and manual processes by January 1, 2001; however, this approach will require increased operator intervention in the market and can be extremely time consuming if settlements must be rerun if refunds are ordered by the Commission. [68] The ISO recommends using an automated approach, but notes it will take approximately four months to implement the automated procedures from the date work commences.

The PX anticipates that it will require a minimum of 90 days, and possibly longer, from the final date of the order to implement this procedure depending upon the chosen remedy. [69] According to the PX, it can either modify its software to calculate the total payment to each supplier that offers energy above $150/MWh or the alternative would be to require any supplier who bids above $150/MWh to offer that energy in the PX's Block Forward Market (BFM) Daily Block Market which is a pay-as-bid market. The PX notes that some software changes would be needed to implement the transactions in the BFM Daily Block market; however, according to the PX, these changes would be relatively easy to make.

The ISO and PX state regardless as to how they implement the Commission's price mitigation proposal, they will need to coordinate with each other and other scheduling coordinators with respect to how the ISO manages congestion. According to the PX, either the ISO must modify the way it calculates the usage charge whenever the energy markets exceed the breakpoint or the PX must modify the way that it collects usage charges whenever the breakpoint is exceeded. In addition, the ISO requests that the Commission impose a cap on the Adjustment Bids that it uses to manage congestion. Moreover, the ISO

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[67] Southern Cities urge the Commission to require the development of a mechanism for informing buyers on a real-time basis of the marginal bids and the resulting weighted average prices such that price signals aren't masked. Southern Cities at 5-6.

[68] ISO comments at 11-13.

[69] PX comments at 45-47.

believes that there is a pending question as to whether the intention in the Order is to cap the constrained market clearing price and pay as-bid, or to allow the market clearing price above $150/MWh to be the basis for payment in such a case. [70]

The Bureau of Economics and of Policy Planning of the Federal Trade Commission (FTC) supports the Commission's requirement that the breakpoint expire after 24 months. FTC believes that, in the long-term, an ongoing breakpoint would likely raise prices, create inefficient plant dispatch, and distort generation and transmission investment decisions. [71] However, CMUA believes that the 24-month transition timetable is optimistic and recommends that the Commission plan for a specific process and affirmative finding that the market is workably competitive before terminating any price mitigation measures. [72] In addition, CMUA argues that the use of opportunity costs to support the as-bid price will set a cap tied to the highest price any buyer is willing to pay and will invite litigation of the as-bid amounts. CMUA asserts that the inclusion of opportunity costs will not bring consumers any protection or provide stability for suppliers.

Metropolitan requests that, if caps are to be implemented, the Commission should also impose a lower price breakpoint during off-peak hours and apply the price cap to the WSCC region. [73] Metropolitan argues that the single price auction will not discipline prices during off-peak hours and a breakpoint with the same reporting requirements as the Commission's proposal is needed to ensure that the price of supply bears a reasonable relationship to demand. [74] SMUD also argues that the Commission's breakpoint and unverifiable inclusion of opportunity costs in the as-bid price will not mitigate market power abuses in either off-peak or peak periods. [75] In addition, SMUD contends that the assumptions used in calculating the $150 breakpoint are unrealistic and overly generous to sellers. SMUD proposes a sliding scale, WSCC-wide, price cap applied to all transactions of one month in duration or less for both peak and off-peak periods. SMUD would calculate its price caps by assuming peak and off-peak heat rate values and using the

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[70] ISO comments at 12.

[71] FTC at 10.

[72] CMUA at 17-20

[73] The County of San Diego and City of Seattle also request that the Commission impose its breakpoint and reporting requirements to the entire western market. County of San Diego at 24 and City of Seattle at 6.

[74] Metropolitan at 13-15.

[75] SMUD at 15-25.

NYMEX Henry Hub price of gas in the calculation. SMUD would apply its price cap to all thermal units with a heat rate less than 14,000 Btu/KWh. Units with a higher heat rate would have a Commission approved cost-of-service rate and these units wouldn't be allowed to set the market clearing price. The City of San Diego requests that the Commission impose hard caps for different types of generators. [76]

Dynegy argues that the Commission needs to clarify that any refund floor associated with as-bid prices should be based upon opportunity costs. Dynegy states that the "known and verifiable" standard was developed in the context of setting transmission rates and that the transmission provider was required to keep records of the specific purchase that was the basis for the opportunity cost calculation. [77] Dynegy contends that this standard will be very difficult to administer in the context of bulk power trading. Dynegy requests that the Commission state that any review of opportunity costs should take into account the imperfect knowledge that typically exists when bids are placed and should recognize the considerable dose of judgement involved in the bidding process. Dynegy asserts that if the Commission implements too rigid of a standard that bidders will be less comfortable selling into California and the supply shortage will worsen. In addition, if the Commission decides not to implement a "bid-ask" market with no caps, Dynegy requests that the Commission refine the breakpoint to account for the recent run-up of natural gas prices (as high as $50/MMBtu at this time). After accounting for the increase in gas costs, Dynegy requests that the Commission update the cap prospectively every month so that increases in gas prices do not trigger reporting requirements.

Williams opposes a cap of any kind. However, according to Williams, if the Commission's breakpoint is implemented, it must be lifted on schedule, i.e., December 31, 2002. In addition, Williams, WPTF, and EPSA propose that the Commission escalate the cap by specific amounts every six months. [78] Williams, WPTF, and Enron also request clarification on the definition of incremental generation and opportunity costs in the reporting requirements for as-bid prices. Williams contends that the generation cost definition should include a contribution to a generator's fixed costs (including actual purchase price) and the opportunity cost definition should include broad market forces such as prices in competing markets and all other non-affiliate bids submitted in blind auctions.

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[76] City of San Diego at 24.

[77] Dynegy at 31-33, citing Pennsylvania Electric Co., 58 FERC ¶ 61,278 (1992) and TransEnergie U.S., Ltd., 91 FERC ¶ 61,230 (2000).

[78] Williams at 11, WPTF at 12, and EPSA at 16.

Calpine notes that the Commission's breakpoint will not affect its plans to develop large base load combined cycle plants in California. [79] In contrast, GE Power Systems notes that since the Commission issued its November 1 Order, GE Power Systems has received cancellations on orders for 14 natural gas turbines, totaling 408 MW of predominantly peaking capacity for projects in California. [80] Calpine states that it is not opposed to the continual monitoring for the 24-month period proposed in the November 1 Order provided that the Commission adopt measures which provide suppliers with price certainty after a relatively brief period. Calpine and PPL Parties recommend that all prices above and below the threshold become final and no longer subject to refund no later than thirty days after the transaction date. In addition, PPL Parties recommend that the Commission exclude new generation from the breakpoint and reporting requirements. [81]

EPSA and Exelon argue that the breakpoint is vague and will discourage new generation from entering the state. To reduce the burden on Commission staff and generators, EPSA proposes that rather than requiring the weekly reporting of all bids above $150, the Commission should require generators to maintain the information that the Commission seeks for a limited period of time. To determine what behavior or bids would trigger review, the Commission should articulate clear standards or market screens with real world examples. Lastly, the Commission should limit the period for reviewing bids. EPSA proposes that a seller be notified within 15 days that its bid is being formally scrutinized and that the Commission should complete its review within 60 days. [82] Southern Energy Parties suggest that the Commission flag reports within 30 days of receiving them and finalize its review within another 30 days. All bids that are not flagged or pass the final 30 day review would no longer be subject to further review or refund. [83] Southern Energy Parties and Reliant recommend a 60 day period following the submission of the data for the Commission to conclude its review.

Enron urges the Commission to abandon any price caps; however, if a cap is implemented, it should be set at a more realistic level and should sunset after 15 months. Enron requests that the Commission clarify that the breakpoint and reporting requirements and any potential refund obligation do not apply to any other exchanges, bilateral deals, or

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[79]Calpine at 14.

[80]GE Power Systems at 3. GE Power Systems notes that due to the backlog of orders for its turbines, customers that cancel their orders lose their priority in the queue and that these customer will face a long wait before its next order can be filled.

[81]PPL Parties at 36.

[82]EPSA at 15-20.

[83]Southern Parties at 49.

forward markets, including the PX's block forward markets. [84] Duke Energy, PPL Parties, Reliant and Southern Energy Parties propose that the breakpoint be raised to the pre-existing ISO cap of $250/MWh. In addition, they request that the Commission set the breakpoint price as a "safe harbor" under which all bids are deemed just and reasonable and exempt from any refund liability. Duke Energy also argues that the inequity of not applying the breakpoint and reporting requirements to non-jurisdictional entities will negate the benefits the Commission sought in eliminating the ISO's hard cap. [85] Duke Energy also suggests criteria concerning how the Commission should review bids.

3. Commission Determination

Commenters propose a wide variety of price mitigation measures that differ from the Commission's $150 single price auction breakpoint and as-bid market. These mitigation measures range from a total return to cost of service based rates to removing all price caps immediately and letting the market fix itself. As discussed below, we continue to believe, despite the volume of comments to the contrary, that the use of the $150 breakpoint and as-bid market combined with the other market changes that we have implemented in this order will discipline prices in California. [86] Moreover, we fully expect the breakpoint to be superseded as a result of our aforementioned adoption of a permanent monitoring plan by May 1, 2001.

We reject proposals to return to cost based regulation. As we discussed in the November 1 Order, prices based upon traditional cost of service are incompatible with fostering a competitive market. As we stated in the November 1 Order, traditional cost-based pricing reflects the cost of the asset without any regard to market conditions. The one thing that California needs most is new supply and a return to traditional cost of service ratemaking will not encourage supply to enter the California market. We note that, under cost-based regulation, California had some of the highest retail rates in the country. Several commenters suggest that the Commission require marginal cost based bids for an interim period similar to the requirement that the Commission initially authorized in the PJM markets. Commenters recommend that such a requirement be imposed on the California market until it can be demonstrated that the markets are competitive.

We reject these proposals for numerous reasons. First, the market structures in PJM differ radically compared to California. When marginal cost bid caps were required in

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[84] Enron at 6-8.

[85] Duke Energy at 43-48.

[86] Effective as of January 1, 2001, the interim $250/MWh breakpoint approved in the December 8 Order will be superseded.

PJM, the participating investor owned utilities of PJM owned their generating assets, and PJM's Interchange Energy Market was a small economy energy market. In addition, PJM has a requirement whereby all load serving entities must have enough resources to meet their forecasted load and a capacity market that provides additional revenues to the generation owners. Because the PJM IOUs had a balanced portfolio of base, intermediate and peaking capacity, there was no financial harm to the PJM IOUs to bid their variable costs, i.e., if their peaking units set the clearing price, their lower cost base and intermediate units were paid the market clearing price and provide a margin sufficient to recover the utilities' fixed costs on all their assets. Unlike PJM, the California IOUs have divested their fossil generation to various entities while retaining their low running cost hydro and nuclear units. The buyers of these assets do not necessarily have a balanced portfolio that can make up any shortfall that arises from paying a peaking unit its variable costs. In the absence of a capacity market, as is the case in California, if a seller only has peaking units, it would only receive the variable cost of energy and no payment for its fixed cost. Sellers could not stay in business for long with that revenue stream. Moreover, there would be no incentive for a generator to bid into a market where the only payment would be its variable cost.

The requirement to bid variable cost also neglects power marketers who do not have any generation. A power marketer's incremental cost is the cost of the power that they acquire. Thus, it is unclear what power marketers would be required to bid. [87] If power marketers are only allowed to pass through the purchase price, they will also shun the California market. The arguments on this point from the California IOUs also appear self-serving given that they own mostly hydro and nuclear generation with running costs of less than $20/MWh which stand to reap the greatest benefits from this proposal.

In addition, we are not persuaded that the $150 breakpoint will cause prices to cluster at that level during low and intermediate peak periods. We have freed the IOUs to self supply their needs. Between their nuclear units, hydro and their existing purchase power contracts, the three IOUs have nearly 25,000 MW available to supply their load during the low and intermediate periods. With this much capacity at their disposal, the IOUs will not be price takers for 25,000 MW of load.

Moreover, the flexibility of the IOUs to self supply their own needs renders the request for a load differentiated price cap a nullity. Most of the low and intermediate peak periods can be supplied by the IOUs through their own generation or existing and future purchase power contracts. This obviates the need for a low price cap during these periods. In addition, there is a problem with imposing a low price cap for low load periods. If a peaking unit must be run during low load periods (for example due to outages of base and

[87] In PJM, the marginal cost bid cap applied only to sales from PJM generating units.

intermediate units), that unit would not be able to recover even its variable cost at the $65/MWh cap proposed by the ISO Board for load levels below 25,000 MW. As we noted earlier, this is a form of cost-based regulation which would jeopardize needed supply entry.

Another problem with the load differentiated price cap proposal is the indexing of gas prices at the NYMEX Henry Hub. Currently, there is a substantial difference in prices at the Henry Hub and at the California border. For instance, gas prices at the Henry Hub for December 4 were $6.50 while prices for that same date at Topock for deliveries to PG&E or Southern California Gas Company ranged from $16 to $18. Given this disparity we are not persuaded that changes in Henry Hub prices correlate to changes in prices in California. The load differentiated price caps are also based upon 1999 prices when market conditions were far better. As noted in the November 1 Order, the favorable factors (e.g., abundant hydro and imports) that were present in 1999 disappeared in 2000. Calculating hypothetical heat rates from 1999 prices that include the dispatch of low cost energy that was not available in 2000 does not produce a reasonable result.

We also will not require sellers to offer fixed rate contracts for portions of their portfolio. Each seller's portfolio contains different types of generating assets with different heat rates. A one size fits all fixed rate would not be practicable. In addition, we note that several sellers already have announced offers to supply large amounts of load to the three IOUs at fixed prices that are less than the average cost of generation for the IOUs in 1998. [88]

A number of commenters take exception to the Commission's assumptions in corroborating the $150 breakpoint. They argue that a more realistic heat rate is 7,500 Btu/kWh and NOx emissions of 0.1 lb/MWh, rather than the 10,000 Btu/kWh and 1.0 lb/MWh figures used in the November 1 Order. However, commenters miss the point of the Commission's calculations. The assumptions are based upon recovering the costs of existing gas fired generation in California while still allowing for a breakpoint that is high enough to allow new more efficient technology to invest in the market without triggering the reporting requirements. Commenters' assumptions are not realistic given the existing generator mix in California, and using their calculations for new generation as the basis for setting the breakpoint would push existing generation from the market. If the existing generation was as efficient as the assumptions used by the commenters opposed to the $150 breakpoint, NOx emission allowances would not be accounting for almost half of the variable cost of electricity.

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[88] According to WPTF at 24, the statewide average cost of generation in 1998 was $67.45/MWh.

While commenters have not provided convincing arguments to lower the breakpoint, neither have they provided convincing arguments to raise it. However, it is apparent from the comments that we need to clarify the use of the $150 breakpoint. Commenters are incorrect that the $150 breakpoint is a cap. The $150 figure simply triggers reporting requirements to the Commission and monitoring and it will be limited to the ISO's markets and the PX Day-Ahead and Day-Of markets (through April 30, 2001). Parties may bid above the $150 breakpoint and we fully realize that sellers will bid above their marginal cost in times of scarcity. As we noted in the November 1 Order, we will not index the $150 to gas and NOx cost changes. We continue to believe that market entry is promoted by simplicity, transparency and stability in price. Indexing the breakpoint would add uncertainty to the market.

As previously noted, a number of commenters express concern with respect to the issue of justifying as-bid prices against opportunity costs. In recognition of the unworkable complexities that the opportunity cost concept introduces in the ISO real-time imbalance market, we will eliminate it. As Dynegy states (at 21) the major cash markets in the west (Palo Verde, California-Oregon Border and Mid-Columbia) close one hour before the California PX Day-Ahead market. This market in turn closes before the ISO ancillary service markets. Therefore, a seller's opportunity to sell in these other markets has already passed. This is particularly true with respect to the ISO real-time energy imbalance market.

In addition, we will not defer the January 1, 2001, implementation for the PX and ISO to run a single price auction below $150 and pay the as-bid price above that level. While the ISO and PX both request additional time to implement software changes, the ISO admits that it can implement the as-bid requirement of the November 1 Order on January 1, 2001. We will direct the PX to put as-bid prices in its BFM Daily Block Market if this procedure is the quickest method to meet the January 1, 2001 deadline. We further direct the ISO, PX and other affected scheduling coordinators to work out the most expeditious way to calculate usage charges for congestion management.

4. Refund Period

The November 1 Order proposed to condition market-based rates on sellers remaining subject to potential refund liability through December 31, 2002 (approximately 27 months) in order to ensure just and reasonable rates during the period it takes to effectuate longer term remedies in the markets. Commenters assert that this condition exceeds the Commission's authority under section 206, which permits refunds for a period of 15 months after the refund effective date, and argue that by proposing this condition, the Commission attempts to do indirectly what it cannot do directly under the FPA. [89]

Dynegy, et al., and Enron comment that the November 1 Order fails to identify any statutory basis for conditioning market-based rates, and Dynegy, et al., cite several Federal court cases for the proposition that the Commission may not use its conditioning authority to circumvent a limitation on its ratemaking authority or to do anything specifically proscribed by statute. [90] PPL states that the Commission has made findings in each case granting market-based rate authority that sellers do not have the means to exercise market power, but has not made any findings here regarding any specific seller that would warrant reversing its earlier conclusions. PPL further contends that courts have required the Commission to limit the broad use of its conditioning power to situations where it has found wide-spread pervasive problems. [91]

The Commission rejects arguments that it may not condition continued approval of market-based rates on the seller agreeing to refund protection in circumstances where, absent such a condition, the Commission cannot find that market-based rate approval will result in just and reasonable rates and adequate protection of ratepayers. There is ample precedent that the Commission may place conditions on its approval of rates where outright approval would not yield just and reasonable results. [92] Courts recognize that imposing a condition can be preferable to the alternatives of rejection or unconditional acceptance. [93] In this order, we have reaffirmed our earlier finding that current market conditions in California leave participants with the potential to exercise market power because of flawed market rules and tight supply conditions, which may lead to rates that are not just and reasonable. As we previously noted, the extended refund liability condition is to ensure

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[89]See, e.g., Williams at 16, XCEL Energy Services at 3, WPTF at 14, and Enron at 9.

[90]See, e.g., Altamont Gas Transmission Co. v. FERC, 92 F.3d 1239, 1246 (D.C. Cir. 1996) (Altamont); Northern Natural Gas Co. v. FERC, 827 F.2d 779, 781 (en banc) (D.C. Cir. 1987) (Northern Natural); National Fuel Gas Supply Corp. v. FERC, 909 F.2d 1519, 1522 (D.C. Cir. 1990) (National Fuel Gas).

[91]PPL at 10, citing Associated Gas Distributors v. FERC, 824 F.2d 981 at 1019 (D.C. Cir. 1987) (Associated Gas).

[92]See e.g., Central Iowa Power Cooperative v. FERC, 606 F.2d 1156 at 1168 (D.C. Cir. 1979).

[93]See, e.g., Trans Alaska Pipeline Rate Cases, 436 U.S. 631 (1978). See also Tapoco, Inc., et al., 39 FERC 61,363 at 62,170-72 (1987); Yankee Atomic Electric Co., et al., 40 FERC 61,372 at 62,218-20 (1987).

just and reasonable rates until such time as the underlying factors are relieved. If sellers do not wish to accept the condition, they are free to seek cost-based rates. However, we do not believe this is the long-term solution that will best provide the consumers in California adequate supply of capacity at the lowest reasonable rate. Further, in light of the technical conference we are ordering to develop more "real-time" prevention of unjust and unreasonable rates, we anticipate that the refund condition may be of relatively short duration.

In response to commenters, we note that we are not imposing this condition on market-based rates pursuant to section 206(b), which provides for a 15-month refund period. While section 206 of the FPA clearly limits our authority to order refunds to the period 15 months following the refund effective date, it does not preclude us from imposing prospective conditions to ensure that future rates are just and reasonable. Indeed, the case law under the FPA requires us in the market rate context to establish a regulatory scheme that "acts as a monitor to see [that rates remain within a zone of reasonableness] or to check rates if it does not." [94] Here, we have instituted monitoring of market rates and, as a consumer protection backstop, we take action pursuant to section 206(a) to condition future approvals on a refund obligation in order to check rates until longer-term remedies are in place.

The cases cited by Dynegy, et al., are inapposite. In these cases, the courts held that the Commission had improperly used its conditioning authority under section 7 of the Natural Gas Act to circumvent the procedural requirements of sections 4 and 5 of that Act (Northern Natural and National Fuel Gas), or to intrude upon state authority (Atlamont). Here, in contrast, we properly abide by FPA section 206's requirements in finding that the existing rates are unjust and unreasonable under certain market conditions and that we can ensure the justness and reasonableness of market-based rates in California's spot markets only by reserving the right to require refunds of charges collected until the end of 2002. Similarly, we reject PPL's argument that we exceed our authority to impose conditions. The prospective refund condition we impose here is carefully tailored to address specific market flaws identified in California's wholesale markets. [95] Our finding that the California market structure and rules provide the opportunity for sellers to exercise market power when supply is tight requires us either to reject or to condition the market-based rates of all sellers into the markets operated by the ISO and the PX for an interim period. We

[94] Farmers Union, 734 F.2d at 1509.

[95] Associated Gas, to the contrary, found Commission action affecting the natural gas industry nationwide was inappropriate where the problem being addressed existed only in isolated pockets.

conclude that conditioning will provide the best means of addressing the market dysfunctions in California.

5. Transaction Reporting Requirements

As we have noted earlier in this order, we will rely on several indicators for monitoring market power, including: the outage rates of the seller's resources, the failure to bid unsold MWs in the ISO's real-time market, and variations in bidding patterns for the same or similar resources.

We clarify that, unless the Commission issues some form of notification to a seller that its transaction is still under review, [96] refund potential on a particular transaction will close 60 days after the initial report is filed with the Commission. The institution of a 60-day period for the review of the transactions will provide sellers with the certainty they request and allows a reasonable period for analysis by staff.

In the November 1 Order, we proposed that all public utility sellers that make sales into the ISO and PX spot markets exceeding $150/MWH file certain transactional information with the Commission on a weekly basis. We also proposed in the Order that the PX and ISO report on a monthly basis all bids in excess of $150 to the Commission. We reaffirm these proposals as described in detail below.

With respect to public utility sellers, they will be required to report confidentially in a single weekly filing all hourly transactions exceeding $150 to the Commission's Division of Energy Market. [97] Such weekly reporting should be submitted by the close of business on the Wednesday following the end of the transaction week (ending Sunday at midnight). For each hourly transaction above $150, the utility seller should provide the following information, in the order listed, in an Excel spreadsheet or comma-delimited electronic file. The seller should provide a single row for each transaction and furnish column headings for the data in the first row of the file, include the following data:

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[96] Once Commission staff has identified transactions that warrant further review, the seller will be notified by a data request, Commission order, or other form of staff or Commission communication. If notification is issued, refund liability will continue until the review is terminated by issuance of a final staff letter or Commission order.

[97] In our view, this reporting requirement and the requirement discussed above on long-term products do not appear to trigger the Paperwork Reduction Act. To avoid any uncertainty, however, we have submitted these requirements for emergency processing pursuant to 5 C.F.R. § 1320.13 (1999).

- transaction identification number (unique identifier for the bid)
- whether the transaction is into ISO or PX market (report ISO or PX)
- the name of the bidder
- transaction identification code as used by PX and ISO
- the generation unit including the identification code as used by PX and ISO
- the energy or ancillary service market
- transaction starting date (mm/dd/yyyy)
- transaction starting time (hh:mm)
- transaction ending date (mm/dd/yyyy)
- transaction ending time (hh:mm)
- the price of megawatts covered by the offer ($/MWh)
- megawatthours covered by the offer
- heat rate (btu/KWh)
- type of fuel (natural gas, oil, coal, and other)
- if not generated, the purchase price and the name of the supplier

The following list of data items should be included in the spreadsheet based on the megawatts in the transaction:

- total fuel quantity
- total fuel cost
- NOx emissions rate (lbs/MWh)
- cost of NOx emissions ($/MWh)
- other environmental compliance costs ($/MWh)
- variable O&M costs
- other costs (document separately)

In addition, the seller must provide:

- outage information for all of the seller's individual resources for the transaction period
- any unsold MWs which the individual seller has failed to bid into the PX or ISO spot markets during the transaction period
- all bids submitted into the PX or ISO spot markets during the transaction period

Moreover, the PX and ISO must make monthly confidential reports to the Director of the Commission's Energy Markets Division for all bids exceeding $150 for all public and non-public utilities. The initial report must be filed no later than February 15, 2001 for the period January 1, 2001 through January 31, 2001. All subsequent reports must be filed no later than 15 days after the end of each calendar month. The Commission staff will meet with representatives from the PX and ISO to finalize the reporting requirements.

F. Governance of the PX and ISO

1. Background

The November 1 Order found that the ISO Governing Board, unable to reach decisions on complex and divisive issues, had become ineffective. The order further noted concerns about the independence of the ISO and PX Boards, as they are comprised of stakeholders who are perceived as being susceptible to influence. Thus, the November 1 Order proposed that the current stakeholder boards be replaced with independent, non-stakeholder boards, effective 90 days after the date of the order. To facilitate a swift transition, the Commission proposed that each new board consist of 7 voting members, with the President/CEO of each entity as a voting member, and that the current Governing Boards of the ISO and PX select the other six members from slates of candidates prepared by an independent consultant. The order also provided guidance on the appropriate qualifications for the new Board members. At the subsequent conference on November 9, 2000, the Commission discussed with various state interests the need to collaborate on a mutually agreeable procedure to facilitate the seating of the new independent Boards.

2. Comments

There appears to be unanimous support among the parties for disbanding the current ISO Governing Board and replacing it with a non-stakeholder board. However, numerous Parties argue that the State of California has a legitimate role in selecting successor board members and should not be excluded from the process.[98] The State's official position, as expressed by the Oversight Board, is for the Governor of California to appoint all members of the Boards, subject to confirmation by the California Senate. Governor Gray Davis avowed in his comments that he will propose legislation to replace the stakeholder Boards with independent Boards and requested the Commission's cooperation in the effort of establishing new ones, noting, "[i]t will little serve the consumers, utilities, merchant generators or other parties to become embroiled in litigation over exactly what powers Congress conferred on the FERC in 1935 . . .." [99] Many parties propose compromise

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[98]See Oversight Board, California Commission, California Legislature, ISO, San Francisco, Southern Cities, SDG&E, CEERT, Metropolitan, and TANC. The ISO states that without changes to the state legislation, actions taken by the new Board may be challenged and requests more time to resolve the conflict in state and federal requirements.

[99]Gov. Davis at 6.

solutions for the selection process that include a role for the State. [100] Several others commenters believe that the Commission should proceed as proposed in the November 1 Order, or urge that California authorities not play a role in selecting new Board members because of excessive political pressure. [101] The California Legislature urges the Commission to resolve these issues in a collaborative manner.

Fewer parties comment specifically about the Governing Board of the PX. Metropolitan recommends that the Commission not impose any particular governance structure on the PX, since it will be in the position of needing to compete with other power exchanges on an equal basis. The Center for Energy Efficiency and Renewable Technologies (CEERT) states that there is no basis for proposing any changes regarding governance of the PX because its Board has always acted cooperatively and productively. The PX's comments request that the Commission revise the time frame for implementing governance changes until 90 days after state/federal concerns have been resolved.

Other frequent comments include the need to ensure significant stakeholder input to the new non-stakeholder boards, through some type of stakeholder committee structure, and requiring that board meetings be subject to open meeting requirements. [102]

3. Commission Determination

While there is general agreement on the need to replace the existing stakeholder Boards, there is no consensus on the process for implementing the transition to an independent Board. State selection of all the board members is not a reasonable position in light of our prior determinations and the current procedures which only allow the state to veto approximately half of the prospective candidates. However, the Commission believes that the state may have an appropriate role in board selection as long as the independence of the board members can be assured (e.g., candidates were limited to the slate provided by the independent consultant). Thus, the Commission will require, as proposed in the November 1 Order, that the ISO Governing Board be replaced with a non-stakeholder Board, and that the members selected to serve on the new Board be independent of market participants. The ISO must continue the search process for new nonstakeholder board members. We also will establish further on-the-record procedures to discuss with state representatives the selection process for the new ISO Board. Because of the complex jurisdictional issues involved and the benefits of avoiding litigation, a specified period of additional time is

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[100] See, e.g., Metropolitan, TANC, TURN/UCAN, Southern Cities, CMUA.

[101] Reliant, Williams, Enron, Calpine, IEP.

[102] Metropolitan, TANC, City of San Diego, Southern Energy.

warranted to attempt a mutually agreeable solution. [103] As the Commission has found it necessary to terminate the PX's rate tariff effective May 1, 2001, as discussed above, there is no need at this time to require replacement of its Governing Board.

Accordingly, on January 29, 2001, ISO Governing Board members must turn over decision-making power and operating control to the management of the ISO, but they will be permitted to continue functioning as members of a stakeholder advisory committee. [104] If no consensus is reached regarding an acceptable means to select new ISO Board members within 90 days thereafter, then the procedures proposed in the November 1 Order will be carried out. Thus, the stakeholder advisory committee will provide input to ISO management until such time as a new Board is seated, or until April 27, 2001, whichever occurs sooner.

During this interim period, the advisory committee members' primary role will be to apprise ISO management of their respective stakeholder views on particular issues. Their role will be limited to providing the ISO with their suggestions on operations, policies and procedures, and providing other recommendations or information as requested by ISO management. Standing committees of the current ISO Board may continue to function by reporting to ISO management. As of January 29, 2001, the ISO Governing Board's bylaws will become null and void to the extent they are inconsistent with these duties.

G. Other Factors Requiring Immediate Action

The California Commission has raised a number of arguments. As discussed below, we conclude that only one – monitoring of outages – requires immediate action.

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[103]The Commission will issue a further order providing details for the discussions. If the parties are amenable, this process may also be used to reach State-Federal consensus on the role and structure of stakeholder advisors for the longer-term. We will permit other (non-State) parties in the proceeding the opportunity for input into and comment on the State-Federal discussions.

[104]We recognize concerns raised by the ISO and others that, without changes to State law, our directive to immediately change the status of the existing Board presents a conflict between State and Federal requirements. We conclude that it is necessary to take this step in order to remedy the dysfunctions in wholesale interstate electricity markets in California and to assure just and reasonable rates. Our hope, however, is to reach a mutually agreeable State/Federal consensus on how the new Board is to be selected and to eliminate conflicts between State and Federal requirements as expeditiously as possible.

The California Commission argues that we should impose price caps and delay our market reform in order to continue investigating the events of the summer of 2000. Price caps will stifle needed supply entry. In addition, California does not have the luxury of unlimited time to study these markets prior to instituting needed immediate market reforms. As noted by the California Commission, the Staff Report acknowledges that because of the expedited basis of the study, staff was not able to address all of the issues in depth and that the intent of the report is to provide the big picture. However, the big picture is abundantly clear that market forces along with the existing market rules played a large part in the increase in prices in California this summer. The California Commission downplays the effects of market forces on price and uses certain discrete findings of the Staff Report to argue that more analysis is needed to determine if sellers exercised market power. For example, the California Commission cites the Staff Report's finding that peak demands during the summer of 2000 were lower than peak demands during the summer of 1999 and that this finding would suggest that higher demands cannot account for the higher prices.

While monthly system peak demands were lower in the summer of 2000 from the previous year, average demand was up 8 to 9 percent over that period. This increase in load caused more fossil generation to run for longer periods of time. In addition, while more energy was being consumed in the California markets, imports, as noted in the Staff Report, were lower from the previous year while exports increased significantly from the same period.

The California Commission criticizes our analysis arguing that the increase in natural gas and NOx costs alone do not fully explain the increase in prices seen in the PX this summer. However, the California Commission's own data, adjusted for the increase in natural gas and NOx costs, show that marginal costs doubled in June 2000 from the previous year and nearly tripled in September 2000 from the previous year. [105] This increase in marginal costs occurred when the output from hydro resources was significantly lower than 1999 levels. [106] With less hydro resources available than the previous year, fossil-fired generation that would have been uneconomical to run in 1999 was needed to make up the shortfall. Much of this older generation has higher heat rates than the assumed 10,000 Btu/MWh value used in the California Commission's example. Thus, higher cost units are setting the market clearing price. As correctly noted in the Staff Report and the November 1 Order, a number of factors working together caused prices to

[105] California Commission Exhibit at 17.

[106] The Staff Report indicates that non-hydro resources generated 24.9 percent more power in June 2000 than the previous year. Staff report at 2-2.

rise. [107] Most troubling is the California Commission's unsupported assertion that NOx costs will decrease next year. This assertion is inconsistent with the fact that increased gas generation is planned and NOx allowances are shrinking.

The California Commission is also critical that we have not sufficiently investigated the increased outage rate of generating units. As previously noted, the Staff report was an informal investigation and that in some instances, the Staff did not have the time to conduct detailed analyses of certain anomalies such as after the fact investigation and verification of plant outages. That said, we agree that timely verification of outages is critical. In this period of tight supply, generation outages whether forced or planned have substantial reliability and price implications. It makes little sense to expect the ISO to operate a reliable transmission system without some assurance and verification that needed generation is available. The ISO has instituted a program of on-the-spot physical inspections of generation stations to verify that the outages are legitimate. Our staff and the California Commission staff are also performing these inspections. We think that timely visual inspection is far preferable to an after-the fact review. We also will direct our staff to perform its own inspections.[108]

H. Interconnection Procedures

1. Background

The November 1 Order noted that standard procedures to facilitate the interconnection of new generators or existing generators seeking to increase the rated

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[107] 93 FERC at 61,359.

[108] Other misplaced criticisms of the Staff Report are that (1) the report said that conclusions about potential market power in August were unclear (staff's report was issued before much of the August data were available); (2) the report proposes that the Commission abandon any effort to evaluate withholding behavior (the report did not argue that the effort should be abandoned); (3) the report mistakenly concludes that, between 1999 and 2000, changes in net imports were due to increases in exports rather than reductions in imports (the report correctly notes that imports were down and exports were up significantly); (4) the report understated the amount of generation available by understating unit capacity (the report was based on actual operating limits in effect during this period, not the maximum capacity ratings generally used for planning purposes; (5) the California Commission's estimate of summer marginal generation costs, based on an extrapolation of summer 1999 prices and changing input prices, differ from data adopted in the report, which was based on the running costs for typical units (credible estimates require simulation studies like those prepared by the MSC).

capacity of their facilities are needed in California. In that regard, we found that the ISO tariff lacks any such procedures and we directed the ISO to file generation interconnection procedures no later than sixty (60) days after the Independent Board is seated. Further, we stated that our proposed timeline would ensure that the Commission may facilitate the matters under its control in a timely manner. [109]

2. Comments

The majority of commenters support the establishment of standard interconnection procedures (IPs) in the ISO Tariff. For example, the California Commission believes that the establishment of such IPs is a useful activity to promote ease of entry of needed new generation in the state, the Department of Energy states that interconnection standards will help remove barriers to technologies which could enhance reliability and reduce price volatility, and TURN/UCAN "wholeheartedly" agrees that standard procedures for new generator interconnection are a high priority. In like manner, the ISO agrees that IPs are critical to the stimulation of efficient generator supply additions, and it commits to file a comprehensive interconnection policy with the Commission by no later than April 2, 2001. The ISO seeks clarification as to its ability, if it is able to do so, to make that filing in advance of any consideration by the ISO Board. [110]

Certain commenters, however, express concern regarding the establishment of IPs. PG&E proposes that the timeline for filing of the IPs be extended to 120 days since the new Board members will have little time to consider the merits of such a proposal. Enron asserts that the IPs should encourage new generation siting and send accurate price signals. Calpine argues that the Commission should direct the ISO to propose IPs consistent with the policies already articulated in previous Commission orders. [111]

3. Commission Determination

We affirm our finding that the ISO must file standard IPs with the Commission, with one modification as discussed below. As we indicated in the November 1 Order, and as commenters cogently note, such procedures will facilitate the addition of new – as well as the expansion of existing – generation in the state, which will in turn enhance system reliability and reduce price volatility. No commenter disputes this fact.

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[109] See November 1 Order, 93 FERC at 61,364-65.

[110] See, respectively, California Commission at 61; Department of Energy at 5; TURN/UCAN at 12-13; and ISO at 24-25. See also AF&PA at 4-5; City of San Diego at 29; EPSA at 12; MG at 16; NEM at 5; and SMUD at 29-30.

[111] See, respectively, PG&E at 46-47; Enron at 23-24; and Calpine at 18.

Further, we agree with Calpine's argument and, accordingly, we hereby place the ISO on notice that we expect its proposed IPs to comport with the policy and precedent already established by the Commission for such filings. [112] Simply put, we do not believe that the structural conditions in California are unique in any significant respect and we see no reason for the ISO's proposal to incorporate any terms or conditions which deviate from those in IPs we have accepted in the past. [113]

Moreover, as discussed elsewhere in this order, the members of the ISO Board will as of January 29, 2001, serve only in an advisory capacity to the ISO's management. Consequently, the ISO will not need the Board's approval before filing its proposed IPs with the Commission. [114]

Finally, upon consideration of the events of the past Summer, we are concerned that requiring only the ISO to file IPs may result in uncertainty regarding interconnection of generation to transmission facilities that are under the control of one of the three California IOUs. In particular, we believe that were we not also to require the IOUs to file such procedures with the Commission, confusion may arise as to the ability of the ISO to require such connections if needed, in turn delaying needed contributions of new or expanded generation capacity to the stability of the grid. Consequently, we will take this opportunity to direct the IOUs to each file with the Commission IPs that are compatible with those developed by the ISO and to do so within the same timeline we have provided for the ISO (i.e., no later than April 2, 2001). The number of IP's that have been filed with the Commission should provide significant guidance for the IOUs and assist them in making timely filings -- to the extent that the IOUs have unique system requirements in their individual filings.

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[112] In particular, we direct the ISO to develop streamlined IPs regarding requests for interconnection of generation units smaller than a certain threshold size. See Southwest Power Pool, Inc., 92 FERC ¶ 61,109 at 61,401, n.5 (2000) (SPP).

[113] See, e.g., Commonwealth Edison Co., 91 FERC ¶ 61,083 (2000), order on compliance filing, 92 FERC ¶ 61,018 (2000); Entergy Services, Inc., 91 FERC ¶ 61,149 (2000); American Electric Power Service Corporation, 91 FERC ¶ 61,308 (2000); and SPP. Further, to the extent that our determination on this matter will simplify development of the ISO's proposal, and in light of our above discussion regarding the ISO Board, we find PG&E's concern regarding time limitations to be without merit. Thus, we deny PG&E's request to extend the ISO's filing deadline.

[114] However, in light of our findings regarding the ISO Board, we will modify the deadline stated in our November 1 Order so that the ISO now must file its proposed IPs no later than April 2, 2001 (rather than 60 days after a new Board is seated).

I. Longer-Term Measures

1. Background

The November 1 Order indicated our belief that the current structure in California requires a number of longer-term reforms in addition to the immediate measures discussed previously. Further, while we stated that we were not dictating any particular revision, we instituted the following longer-term measures: (1) directing the ISO and the Load Serving Entities in California to consider what market rules are needed to ensure that sufficient supply is available to meet loads and reserve requirements; (2) directing the PX and the ISO to consider, during the 24-month transition period window, whether alternatives to the single price auction which minimize the ability of sellers to bid for the purpose of setting the clearing price may be appropriate; (3) directing the ISO and the PX to pursue establishing an integrated day-ahead market in which all demand and supply bids are addressed in one venue; (4) directing the ISO and the PX to consider less intrusive, narrowly tailored market protection mechanisms (e.g., ex ante identification of conditions or behavior that would trigger specific market mitigation actions); (5) directing the new ISO Board to file its congestion management redesign proposal no later than sixty (60) days after the Board is seated with an implementation date as soon as possible, and requiring that the proposal provide a comparison with a nodal energy price proposal (i.e., locational marginal prices for each bus or node on the grid); and (6) directing the ISO and Scheduling Coordinators to consider demand bidding programs in which loads can bid offers of demand reduction directly into the market to compete with offers of supply. In addition, we stated our expectation that the matters addressed in the November 1 Order will move the California market toward meeting the significant objectives of Order No. 2000 and that the preceding long-term market reforms will facilitate California's transformation into a properly sized and functioning RTO. [115]

2. Comments

A large number of commenters express their support for the long-term measures proposed in the November 1 Order, although most of the comments in this regard also include requests that the Commission either provide more explicit direction or, conversely, that we refrain from being overly prescriptive in our direction. For instance, the Oversight Board contends that the Commission's proposal regarding an integrated day-ahead market is ambiguous and should be clarified to provide a much clearer statement of direction, [116] but it also believes that the appropriate size and scope of a California-based RTO is separate

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[115] See November 1 Order, 93 FERC at 61,365-66.

[116] See Oversight Board at 19.

from the fundamental questions before the Commission in this proceeding and, consequently, need not be decided herein. Other comments generally focus on one or more of the following categories: (1) the specific type of congestion management design to be utilized by the ISO (e.g., the ISO should be required to adopt a congestion management design based on locational marginal pricing rather than zonal pricing); [117] (2) the specific types of demand response programs to be utilized by the ISO (e.g., the ISO should be required to designate curtailable load as an ancillary service); [118] and (3) the formation of a WSCC-wide RTO and the requirement that the ISO to join such an entity. [119]

On a more specific level, San Francisco complains that the November 1 Order's 60-day filing requirement deadline for the congestion management reform proposal [120] may not be adequate given the significant gaps in design and analysis of the proposals presented to stakeholders to date. Further, San Francisco argues that the 60-day deadline may force the ISO's staff to recommend an inadequate proposal or one which has been completed but is poorly understood because there has been insufficient opportunity for analysis. San Francisco recommends that 60-day deadline be modified in two respects: (1) a fully designed and described congestion management redesign proposal and a cost impact study of that proposal should be presented to stakeholders in sufficient time to allow them to understand the proposal and to prepare meaningful commentary to the ISO Board; and (2) the 60-day deadline should begin once a meeting of newly-seated Board members is presented with a staff presentation, the results of a cost impact study, and the receipt of public comment (along with sufficient time to consider such comment). Similarly, Metropolitan expresses concern that the newly-seated ISO Board will have insufficient time to review the ISO's proposal, and it requests that the filing requirement deadline be extended to 120 days. [121]

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[117] See, e.g., Cities/M-S-R at 3-4; City of Seattle at 5-6; CMUA at 7; Dynegy at 40-43; Elcon, et al., at 16-17; Exelon at 9; ISO at 21-24; FTC at 7, n.17; NEM at 8; NYMEX at 11; SDG&E at 28 and 33-34; TURN/UCAN at 14-15; and San Francisco at 8-10.

[118] See, e.g., ACWA at 3-5; APX at 3; BP Energy at 12-13; DWR at 5-9; Elcon, et al., at 13-14; ISO at 25-26; Metropolitan at 17-19; MG at 6-8 and 17-18; NEM at 7; New West at 2-3; Puget Sound at 10-12; SMA at 7-8; and TURN/UCAN at 15.

[119] See e.g., AF&PA at 4; BP Energy at 14-15; Calpine at 17-18; Cities/M-S-R at 4-5; Elcon, et al., at 14-16; FTC at 12; MG at 4-5 and 18; NEM at 8-9; TANC at 9-12; and TURN/UCAN at 15-16.

[120] See November 1 Order, 93 FERC at 61,365-66.

[121] See, respectively, San Francisco at 10-11; Metropolitan at 15-16.

3. Commission Determination

Although we appreciate the concerns raised by commenters with respect to the possible need for further guidance, we will decline at this time to issue more prescriptive direction for our long-term measures than that already stated in our November 1 Order. We have carefully weighed the pros and cons of providing any such direction with the need to ensure that the ISO presents us with a proposal or series of proposals that provide a synergy of effort and that result in the most workable and efficient market possible. On balance, we are concerned that any prescriptive direction we would issue could not possibly account for the myriad facets of the ISO's restructuring effort, thus such direction would merely serve as an impediment to those efforts and would delay – and/or significantly diminish the quality – of the ISO's final market design. Moreover, not issuing such direction at this time will allow all interested parties the opportunity to provide more specific and focused commentary once the relevant proposals are filed with the Commission.

In addition, we decline to prejudge the ability of the ISO's staff to develop a comprehensive and well-thought congestion management redesign proposal. The ISO has not requested an extension of time to file that proposal and we will not create one only on the basis of commenter's remarks. Further, as discussed elsewhere in this order, the members of the ISO Board will as of January 29, 2001, serve only in an advisory capacity to the ISO's management and may file comments on the ISO's proposal once it has been submitted to the Commission. Accordingly, we deny San Francisco's and Metropolitan's requested modifications.

While we decline to prescribe particular long-term market reforms at this time, we wish to establish a forum for their resolution. We therefore direct our staff to convene a technical conference to explore the best long-term measures to address California's wholesale markets. We direct that this conference include the issues of: (1) the adoption of security-constrained unit commitment dispatch; (2) the use of simultaneous rather than sequential auctions; (3) the creation of an installed capacity market; (4) the establishment of reserve requirements; and (5) demand-side response programs. We will issue a subsequent order on these matters at a later date.

We will make two other modifications to our proposed longer-term measures. First, insofar as we have terminated the PX's wholesale tariff and rate schedules elsewhere in this order effective May 1, 2001, we will no longer require the PX to institute any applicable longer-term measure. Second, the Commission directed the ISO to undertake a comprehensive redesign of its congestion management process. In response, the ISO began the process in March 2000 with numerous working group and individual market participant meetings. By September 2000, a revised congestion management process was submitted to the ISO Board for approval. The ISO Board approved the creation of eleven Locational

Pricing Areas (LPAs). LPAs are based upon engineering requirements, criteria and practices that guide real-time operation to ensure grid reliability. The ISO predicts that this new program will effectively manage most, if not all congestion in California based upon a comparison to full nodal pricing. We direct the ISO to file the redesign proposal. In light of our findings regarding the ISO Board, we will modify the deadline stated in our November 1 Order so that the ISO now must file its congestion management redesign proposal no later than January 31, 2001 (rather than 60 days after a new Board is seated).

For the above reasons, we affirm the November 1 Order's proposed longer-term measures, with the modifications as discussed above.

J. Other Matters

1. Qualifying Facility (QF) Issues

A. Increased Output from QF Facilities

Ridgewood states that the total power production capacity of QFs in California is approximately 9,000 MWs, of which, between 4,000 and 5,500 MW are from qualifying cogeneration facilities (Cogeneration QFs) and the remainder from small power production facilities (Small Power QFs). Ridgewood states that the Cogeneration segment of the industry is underutilized because of operating efficiency and other QF requirements. [122] With a limited waiver or other equivalent relief, these underutilized resources could help relieve current shortages during both peak and off-peak period. Ridgewood estimates that as much as 1,000 MWs would be immediately available by allowing QFs to sell to the purchasing utility or into the competitive market their "above-baseline" output for a limited time period. [123] Ridgewood suggests that any such sale would be made at market-based rates and would not be subject to the operating and efficiency standards. Rigdewood cites Fresno Cogeneration Partners, L.P., 92 FERC ¶ 61,230 (2000) (Fresno Cogen), stating that the Commission has granted waivers to Cogeneration QFs that entered into restructuring arrangements with their purchasing utilities and should allow the same flexibility to all Cogeneration QFs in the California market.

[122] These requirements contain formulas that tie any increases in the total energy output and total power input of a facility to corresponding increases in the thermal energy output. 18 C.F.R. § 292.205 (2000).

[123] Ridgewood suggests that the baseline output for each facility be calculated using the seasonal averages of output over two to three years of recent operating history. Ridgewood at 9.

Ridgewood also states that similar efficiencies could be gained from relaxing the restrictions on Small Power QFs in California. The use of oil, natural gas, or coal by any Small Power QF is limited under PURPA unless waiver is granted.[124] Ridgewood suggests that such a waiver, along with action on the Cogeneration QF efficiency standards would provide the largest benefit to California consumers.

The Commission considered these comments in an order issued on December 8, 2000, granting emergency waiver of certain QF regulations through January 1, 2001.[125] For the reasons cited in that order, we will extend the waiver of 18 C.F.R. §§ 292.204 and 292.205 through April 30, 2001.

B. PX based Pricing for QF Contracts

Cogeneration Association and Calpine express concern about the pricing of power sold from their QF units under long-term contracts with California IOUs. Cogeneration Association states that California Public Utilities Code, Section 390(c) ties the Cogeneration QF energy price to the PX price. These resources, which are bid into the California PX market at zero, are thus price takers and will receive the PX Day-Ahead energy price as an hourly energy payment. Calpine states that because its units have heat rates that vary from 10,000 to 13,000 BTU/KWh, at times of high gas prices these units will substantially exceed the $150/MWh breakpoint. Calpine states moreover that there is no mechanism under the current rate structure to allow Calpine to bid the actual cost of these units to the extent that the cost exceeds the $150/MWh level. Therefore, these units may not run if their current rates are not modified.[126]

Calpine and Cogeneration Association have raised legitimate concerns regarding the pricing and associated availability of Cogeneration QF resources in the California market. However, as stated by Cogeneration Association, this issue derives from the California Public Utility Code and in the first instance is within state authority. In this order, we eliminate the PX buy/sell requirement and terminate the PX rate schedule. These changes to the California market structure require necessary actions by California authorities in order to determine the appropriate avoided cost rate for Cogeneration QF power, a determination, as stated by PURPA, within the purview of the states.

2. Requests for Regional Price Cap

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[124] 18 C.F.R. § 292.204(b) (2000).

[125] San Diego Gas & Electric Company, et al., 93 FERC ¶ 61,238 (2000).

[126] Calpine at 14. Cogeneration Association at 14.

Despite the fact that the November 1 Order did not address this matter, five commenters request that the Commission impose a price cap – or some other California-based market mitigation mechanism – on the entire Western region. In support, the commenters observe that the November 1 Order recognized that California is not electrically isolated from the remainder of the Western Region and that, over time, California utilities have increasingly relied on imports from generation located in neighboring states to meet their load requirements and have constructed significant transmission interties to import electricity for California consumers. Conversely, CE Generation LLC argues that a regional pricing mechanism would be unjust and unreasonable insofar as there is no evidence in the record that utilities outside of California have caused the rates for service to become unjust or unreasonable, nor is there any evidence that would justify a finding that the rates of any utility outside of California are unjust and unreasonable. [127]

Although we agree with the commenters that the Western region of the U.S. is an integrated electricity market, [128] we will decline to adopt a region-wide price cap at this time. There are no organized electricity markets outside of California to which a price cap could be applied, i.e., with the exception of California, there are no ISO or PX markets currently operating anywhere in the region. The majority of transactions that occur in the region do so on a bilateral basis. [129]

Moreover, under the Federal Power Act, upon complaint or on our own motion, the Commission may establish new rates only if it first has a record to determine that the existing rates are unjust, unreasonable, unduly discriminatory or preferential. Further, once such a finding is made as to existing rates, the Commission must have a record to support the new rate it establishes as just and reasonable. The record in this consolidated hearing proceeding only extends to sales into the ISO and PX markets; thus, the Commission has little or no evidence on which to assess prices of bilateral transactions either within California or elsewhere in the Western region. While the issue of generation supply

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[127]See California Legislature at 10; County of San Diego at 22-24; Metropolitan at 12; Oversight Board at 24-26; and Puget Sound at 9-10 (reiterating its arguments on complaint as discussed elsewhere in this order). See also CE Generation at 10-11.

[128]See November 1 Order, 93 FERC at 61,357-58, for a detailed discussion of the integrated nature of the Western region markets.

[129]E.g., bilateral contracts often contain provisions which index damages for non-performance to certain index prices (i.e., so-called "mark-to-market" provisions). Thus, the imposition of a regional price cap could potentially result in an alteration of the existing terms and conditions of a myriad of bilateral contracts, resulting in an undue burden for all concerned.

availability in California is an important one, no commenter has submitted evidence that conclusively demonstrates that the adoption of regional price cap would beneficially influence the availability of supplies in California. In addition, no commenter has documented a single instance of a seller outside of California exercising market power during times of scarcity. In sum, the commenters have not met the burden of showing that a price cap on all sellers supplying energy and ancillary services in the Western region is justified and in the public interest.

K. Related Complaints and Other Filings

Consistent with our discussion in this order, we will reject the various proposals and complaints regarding the imposition of price caps or cost-based rates – i.e., the Oversight Board's complaint in Docket No. EL00-104-000, CMUA's complaint in Docket No. EL01-1-000, the ISO's Offer of Settlement in Docket No. EL00-95-003, et al., and Puget's complaint in Docket No. EL01-10-000. The modifications we are establishing in this order are intended to provide for uniform pricing and to remove incentives for the load and resources to participate in one market over another. For this reason, we decline to direct the implementation of pricing methodologies that will disrupt this uniformity or to introduce new incentives in the markets. Furthermore, in the case of Puget Sound's complaint, and as also consistent with our discussion elsewhere in this order, we decline to implement a region-wide price cap because such a pricing methodology is impracticable given the market structure in the Northwest, nor has the burden of proof been met to justify such an action.

Moreover, we reject Joint Complainants' complaint filed in Docket No. EL00-97-000 for several reasons. First, in light of the findings made by the Commission in this order, Joint Complainants' assertions regarding the adverse impacts of a reduced price cap are no longer relevant. We believe that as a result of the pricing methodology adopted in this order, generators should no longer have incentive to seek markets other than those in California. Second, the precedent established in Morgan Stanley is simply not applicable in this instance since it does not address – nor was it intended to address – the issue of curtailments for the maintenance of system reliability. Third, contrary to Joint Complainants' contention, the ISO Tariff does in fact contain a compensation mechanism for curtailments of exports. That mechanism was accepted by the Commission as part of the ISO' Tariff Amendment No. 23 [130] and, to the extent Joint Complainants' complaint challenges the relevant Commission-approved Tariff provisions, we reject their arguments as a collateral attack on our previous orders.

[130] See California Independent System Operator Corp., 90 FERC ¶ 61,006 (2000), reh'g denied, 91 FERC ¶ 61,026 (2000), order on compliance filing, 90 FERC ¶ 61,165 (2000).

With respect to CARE's complaint filed in Docket No. EL01-2-000, we will deny CARE's petitions regarding California market conditions as well as its petitions regarding the initiation of DOJ investigations. Simply put, CARE has failed to meet its burden of proof inasmuch as did not provide adequate evidence in support of its allegation of an ISO/generator trust, nor did it document a single instance of restraint of trade or civil rights violations. In any event, the matter of whether the alleged violations warrant the initiation of DOJ investigation is clearly not within the Commission's jurisdiction.

We will accept without modification the ISO's proposed Tariff Amendment No. 30 filed in Docket Nos. EL00-95-002 and EL00-98-002, and we will grant the effective date requested by the ISO. Regarding intervenors' concerns that the ISO be limited in its use of forward contracting, we believe that the findings made in this order, particularly those intended to significantly reduce underscheduling, will serve that purpose. To the extent that the ISO's need to procure energy for the real-time market will be significantly reduced, its need to procure energy through forward contracting will be lessened accordingly. In addition, with respect to the issue of the ISO's proposed allocation methodology, we find intervenors' arguments on this matter to be without merit. The proposed methodology merely allocates costs in a manner consistent with other such methodologies that we have accepted in the past, [131] and no party has presented arguments which persuade us to reject it.

The Commission orders:

(A) We hereby terminate the PX's rate schedules effective as of the close of the April 30, 2001, trading day.

(B) We hereby terminate the authority of PG&E, SoCal Edison, and SDG&E to sell their resources into the PX effective as of the date of this order. The companies are hereby directed to submit compliance filings effecting this change within 15 days of the date of this order.

(C) The ISO and PX are hereby directed to submit compliance filings as discussed in the body of this order within 15 days of the date of this order.

(D) The bylaws of the ISO are hereby declared to be null and void effective as of January 29, 2001, as discussed in the body of this order.

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[131] See, e.g., California Independent System Operator Corporation, 91 FERC ¶ 61,256 (2000), reh'g pending.

(E) We hereby direct the ISO, PX, and all public utility sellers that make sales into the ISO and PX spot markets to file information regarding certain transactions and bids, as discussed in the body of this order.

(F) We hereby direct the ISO, PG&E, SoCal Edison, and SDG&E to file Interconnection Procedures no later than April 1, 2001.

(G) The Commission staff is hereby directed to convene a technical conference to develop monitoring and mitigation program, as discussed in the body of this order, and is directed to submit a proposed monitoring plan no later than March 1, 2001.

(H) The ISO is hereby directed to file a congestion management redesign proposal no later than January 31, 2001.

(I) We hereby grant waiver of 18 C.F.R. §§ 292.204 and 292.205, as discussed in the body of this order.

(J) We hereby accept for filing the ISO's Tariff amendments filed in Docket Nos. EL00-95-002 and EL00-98-002.

(K) We hereby dismiss the complaints filed in Docket Nos. EL00-97-000, EL00-104-000, EL01-1-000, EL01-2-000, and EL01-10-000.

By the Commission. Chairman Hoecker concurred with a separate statement to be issued later.
(S E A L) Commissioners Massey and Hébert concurred with separate statements attached.

David P. Boergers,
Secretary.

Appendix A - Intervenors and Respondents

Intervenors to Consolidated Hearing Proceeding in Docket No. EL00-95-000, et al.
AES NewEnergy, Inc. *
AES Pacific, Inc.
Alcoa Inc., Columbia Falls Aluminum Company, and Kaiser Aluminum & Chemical Corporation (jointly) *
American Association of Business Persons with Disabilities
American Forest & Paper Association * (AF&PA)
Arizona Districts
Arizona Residential Utility Consumer Office, New Mexico Attorney General, and the Colorado Office of Consumer Counsel (jointly) *
Atofina Chemicals, Inc., Goldendale Aluminum Company, and Northwest Aluminum Company (jointly) *
Automated Power Exchange, Inc. * (APX)
Bonneville Power Administration * (Bonneville)
BP Energy Company * (BP Energy)
California Department of Water Resources * (DWR)
California Electricity Oversight Board * (Oversight Board)
California Hydropower Reform Coalition and Environment Defense (jointly)
California Independent System Operator Corporation * (ISO)
California Manufacturers and Technology Association
California Municipal Utilities Association * (CMUA)
California Power Exchange Corporation * (PX)
California Small Business Association and California Small Business Roundtable (jointly) *
Calpine Corporation * (Calpine)
CE Generation LLC * (CE Generation)
Cities of Anaheim, Azusa, Banning, Colton, and Riverside, California (jointly) * (Southern Cities)
Cities of Redding, Santa Clara, and Palo Alto, California, and the M-S-R Public Power Agency (jointly) * (Cities/M-S-R)
City and County of San Francisco, California * (San Francisco)
City of Dana Point, California
City of Escondido, California
City of Poway, California
City of San Diego, California * (City of San Diego)
City of Seattle, Washington * (City of Seattle)
City of Vernon, California (City of Vernon)
City of Vista, California
County of San Diego, California (County of San Diego) *
Cogeneration Association of California and Energy Producers and Users

Coalition (jointly) * (CAC/EPUC)
Constellation Power Source, Inc.
Consumers First
Coral Power, L.L.C.
Duke Energy North America LLC, Duke Energy Trading and Marketing, LLC, and Duke Energy Merchants, LLC (jointly) * (Duke)
Dynegy Power Marketing, Inc., El Secunda Power, LLC, Long Beach Generation LLC, Cabrillo Power I LLC, and Cabrillo Power II LLC (jointly) * (Dynegy, et al.)
El Paso Merchant Energy, L.P. (El Paso)
Electricity Consumers Resource Council, American Iron and Steel Institute, and American Chemistry Council (jointly) * (Elcon, et al.)
Electric Power Supply Association * (EPSA)
Enron Power Marketing, Inc., and Enron Energy Services, Inc. (jointly) * (Enron)
Exelon Corporation * (Exelon)
FPL Energy, LLC *
H.Q. Energy Services (U.S.), Inc.
Independent Energy Producers Association * (IEP)
Industrial Customers of Northwest Utilities *
Internal Services Department of Los Angeles County
Merced Irrigation District
Merrill Lynch Capital Services, Inc.
Metropolitan Water District of Southern California * (Metropolitan)
MG Industries * (MG)
Modesto Irrigation District * (Modesto)
Morgan Stanley Capital Group Inc.
Mr. Mark B. Lively
Multiple Intervenors *
New West Energy Corporation * (New West)
New York Independent System Operator, Inc.
New York Mercantile Exchange * (NYMEX)
North Star Steel Company *
Northern California Power Agency * (NCPA)
NRG Power Marketing, Inc.
Orion Power New York, Inc.
Pacific Gas and Electric Company * (PG&E)
PacifiCorp *
Pinnacle West Companies (Pinnacle)
PJM Industrial Customer Coalition and Coalition of Midwest Transmission Customers (jointly) *
Portland General Electric Company
PPL EnergyPlus, LLC and PPL Montana, LLC (jointly) * (PPL)
Public Service Electric and Gas Company, PSEG Energy Resources & Trade LLC, and

PSEG Power LLC (jointly) *
Public Utilities Commission of California * (California Commission)
Puget Sound Energy, Inc. * (Puget Sound)
Reliant Energy Power Generation, Inc. * (Reliant)
Ridgewood Power LLC * (Ridgewood)
Sacramento Municipal Utility District * (SMUD)
San Diego Gas & Electric Company * (SDG&E)
Secretary of the U.S. Department of Energy * (Department of Energy)
Shell Energy Services Company, L.L.C. *
Southern California Edison Company * (SoCal Edison)
Southern Energy California, L.L.C., Southern Energy Delta, L.L.C., and Southern Energy Potrero, L.L.C. (jointly) * (Southern Energy)
The Utility Reform Network * (TURN)
Transmission Agency of Northern California * (TANC)
Watson Cogeneration Company *
Western Power Trading Forum * (WPTF)
Williams Energy Marketing & Trading Company * (Williams)

* - indicates that party also submitted comments in response to the Commission's November 1 Order.

<u>Intervenors and Respondents to Complaint in Docket No. EL00-97-000</u>
California Department of Water Resources
California Electricity Oversight Board
California Independent System Operator Corporation
California Manufacturers and Technology Association
California Power Exchange Corporation
Cities of Redding, Santa Clara, and Palo Alto, California, and the M-S-R Public Power Agency (jointly)
Duke Energy North America LLC, Duke Energy Trading and Marketing, LLC, and Duke Energy Merchants, LLC (jointly)
Electric Power Supply Association
Metropolitan Water District of Southern California
Modesto Irrigation District
Morgan Stanley Capital Group Inc.
New York Mercantile Exchange
Northern California Power Agency
Pacific Gas & Electric Company
Portland General Electric Company
Public Utilities Commission of the State of California
Sacramento Municipal Utility District
San Diego Gas & Electric Company

Southern California Edison Company
Transmission Agency of Northern California
Williams Energy Marketing & Trading Company

<u>Intervenors and Respondents to Complaint in Docket No. EL00-104-000</u>
Bonneville Power Administration
California Department of Water Resources
California Independent System Operator Corporation
California Municipal Utilities Association
California Power Exchange Corporation
Cities of Anaheim, Azusa, Banning, Colton, and Riverside, California (jointly)
Cities of Redding, Santa Clara, and Palo Alto, California, and the M-S-R Public Power Agency (jointly)
City of Vernon, California
Cogeneration Association of California and the Energy Producers and Users Coalition (jointly)
Duke Energy North America LLC, Duke Energy Trading and Marketing, LLC, and Duke Energy Merchants, LLC (jointly)
El Paso Merchant Energy, L.P.
Electric Power Supply Association
Enron Power Marketing, Inc., and Enron Energy Services, Inc. (jointly)
Independent Energy Producers Association
Merrill Lynch Capital Services, Inc.
Modesto Irrigation District
Morgan Stanley Capital Group Inc.
New York Mercantile Exchange
Northern California Power Agency
Pacific Gas and Electric Company
Pinnacle West Companies
Public Utilities Commission of the State of California
Reliant Energy Power Generation, Inc., and Reliant Energy Services, Inc. (jointly)
Sacramento Municipal Utility District
San Diego Gas & Electric Company
Southern California Edison Company
Southern Energy California, L.L.C., Southern Energy Delta, L.L.C., and Southern Energy Potrero, L.L.C. (jointly)
Transmission Agency of Northern California
Western Area Power Administration
Western Power Trading Forum
Williams Energy Marketing & Trading Company

<u>Intervenors and Respondents to Complaint in Docket No. EL01-1-000</u>

AES NY, L.L.C.
American Public Power Association
Bonneville Power Administration
California Department of Water Resources
California Electricity Oversight Board
California Independent System Operator Corporation
California Large Energy Consumers Association
California Manufacturers and Technology Association
California Power Exchange Corporation
Cities of Anaheim, Azusa, Banning, Colton, and Riverside, California (jointly)
Cities of Redding, Santa Clara, and Palo Alto, California, and the M-S-R Public Power Agency (jointly)
City of San Diego, California
City and County of San Francisco, California
Cogeneration Association of California and the Energy Producers and Users Coalition (jointly)
Coral Power, L.L.C.
Duke Energy North America LLC, Duke Energy Trading and Marketing, LLC, and Duke Energy Merchants, LLC (jointly)
Electric Power Supply Association
Enron Power Marketing, Inc., and Enron Energy Services, Inc. (jointly)
Merrill Lynch Capital Services, Inc.
Modesto Irrigation District
Morgan Stanley Capital Group Inc.
New York Mercantile Exchange
Northern California Power Agency
Pacific Gas and Electric Company
Pinnacle West Companies
PPL Montana, LLC, and PPL EnergyPlus, LLC (jointly)
Public Utilities Commission of the State of California
Puget Sound Energy, Inc.
Reliant Energy Power Generation, Inc., and Reliant Energy Services, Inc. (jointly)
Sacramento Municipal Utility District
Southern California Edison Company
Southern Energy California, L.L.C., Southern Energy Delta, L.L.C., and Southern Energy Potrero, L.L.C. (jointly)
Tractebel Power, Inc.
Transmission Agency of Northern California
Turlock Irrigation District
Western Area Power Administration
Williams Energy Marketing & Trading Company

<u>Intervenors and Respondents to Complaint in Docket No. EL01-2-000</u>
Bonneville Power Administration
California Department of Water Resources
California Independent System Operator Corporation
California Large Energy Consumers Association
California Manufacturers and Technology Association
California Power Exchange Corporation
Cities of Redding, Santa Clara, and Palo Alto, California, and the M-S-R Public Power Agency (jointly)
City and County of San Francisco, California
Cogeneration Association of California and the Energy Producers and Users Coalition (jointly)
Duke Energy North America LLC, Duke Energy Trading and Marketing, LLC, and Duke Energy Merchants, LLC (jointly)
Dynegy Power Marketing, Inc., El Secunda Power, LLC, Long Beach Generation LLC, Cabrillo Power I LLC, and Cabrillo Power II LLC (jointly)
Enron Power Marketing, Inc., and Enron Energy Services, Inc. (jointly)
Independent Energy Producers Association
Merrill Lynch Capital Services, Inc.
Modesto Irrigation District
Morgan Stanley Capital Group Inc.
New York Mercantile Exchange
Northern California Power Agency
Pacific Gas and Electric Company
Pinnacle West Companies
PPL Montana, LLC, and PPL EnergyPlus, LLC (jointly)
Public Utilities Commission of the State of California
Reliant Energy Power Generation, Inc., and Reliant Energy Services, Inc. (jointly)
Sacramento Municipal Utility District
Southern California Edison Company
Southern Energy California, L.L.C., Southern Energy Delta, L.L.C., and Southern Energy Potrero, L.L.C. (jointly)
Tractebel Power, Inc.
Transmission Agency of Northern California
Williams Energy Marketing & Trading Company

<u>Intervenors and Respondents to Complaint in Docket No. EL01-10-000</u>
Alcoa Inc., Atofina Chemicals, Inc., Goldendale Aluminum Company, Kaiser Aluminum & Chemical Corporation, Northwest Aluminum Company, and Reynolds Metal Company (jointly)
Avista Corporation and Avista Energy, Inc. (jointly)
California Independent System Operator Corporation

Cities of Redding, Santa Clara, and Palo Alto, California, and the M-S-R Public Power Agency (jointly)
Cogeneration Coalition of Washington
Columbia Falls Aluminum Company
Duke Energy North America LLC, Duke Energy Trading and Marketing, LLC, and Duke Energy Merchants, LLC (jointly)
Enron Power Marketing, Inc., and Enron Energy Services, Inc. (jointly)
Idaho Power Company
Industrial Customers of Northwest Utilities
Modesto Irrigation District
PacifiCorp
Pinnacle West Companies
Portland General Company
PPL Montana, LLC, and PPL EnergyPlus, LLC (jointly)
Sacramento Municipal Utility District
Southern California Edison Company
Transalta Energy Marketing (US) Inc., Transalta Centralia Generating LLC, and AES Pacific, Inc. (jointly)
Transmission Agency of Northern California

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company, Complainant, v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange, Respondents.	Docket Nos. EL00-95-000 EL00-95-002 EL00-95-003
Investigation of Practices of the California Independent System Operator and the California Power Exchange	Docket Nos. EL00-98-000 EL00-98-002 EL00-98-003
Public Meeting in San Diego, California	Docket No. EL00-107-000
Reliant Energy Power Generation, Inc., Dynegy Power Marketing, Inc., and Southern Energy California, L.L.C., Complainants, v. California Independent System Operator Corporation, Respondent.	Docket No. EL00-97-000
California Electricity Oversight Board, Complainant, v. All Sellers of Energy and Ancillary Services Into the Energy and Ancillary Services Markets Operated by the California Independent System Operator and the California Power Exchange, Respondents.	Docket No. EL00-104-000
California Municipal Utilities Association, Complainant, v. All Jurisdictional Sellers of Energy and Ancillary Services Into Markets Operated by the California	Docket No. EL01-1-000

Independent System Operator and the
California Power Exchange,
Respondents.

Californians for Renewable Energy, Inc. (CARE),
Complainant,
v.
Independent Energy Producers, Inc., and All Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange; All Scheduling Coordinators Acting on Behalf of the Above Sellers; California Independent System Operator Corporation; and California Power Exchange Corporation,
Respondents.

Docket No. EL01-2-000

Puget Sound Energy, Inc.,
Complainant,
v.
All Jurisdictional Sellers of Energy and/or Capacity at Wholesale Into Electric Energy and/or Capacity Markets in the Pacific Northwest, Including Parties to the Western Systems Power Pool Agreement,
Respondents.

Docket No. EL01-10-000

(Issued December 15, 2000)

MASSEY, Commissioner, concurring:

It is no secret that I have been deeply concerned about the apocalypse occurring in California power markets. Prices have not been just and reasonable, and market power has been exercised. Today's order re-emphasizes these critical findings. As a result, the transfer of wealth from purchasers of power to sellers has been absolutely staggering and completely defies the public interest. No legitimate public purpose has been furthered by this regrettable spectacle. The State's two largest utilities are virtually bankrupt because the billions in wholesale power purchase costs vastly exceed the amounts they have been allowed by state policy to recover from their customers. This is, of course, a mixed blessing -- it bankrupts the utilities yet in the short term protects the bulk of the State's consumers from these astronomical prices. Yet it is not sustainable long term, and it serves no legitimate policy interest to bankrupt the utilities. It seems rather clear to me that some day soon a federal court, if asked, will declare that the utilities are entitled as a matter of federal preemption to recover these high wholesale costs from their customers. That's the way I read applicable precedent such as Nantahala, Narragansett, and Mississippi Power & Light.[1] And once these costs are passed through, of course the entire state, not just San Diego, will be in a perfectly legitimate and understandable uproar.

Meanwhile, virtually no new generation has been installed in California in over ten years, although substantial new generation is in the process of being sited by California officials. In addition, substantial transmission additions are necessary to eliminate bottlenecks that prohibit cheaper power from reaching consumers. These are problems that California officials must work to resolve, and I encourage them to do so.

In this context, there is a lot to like in this order. It is a very worthy effort to deal with the market meltdown in California. It forcefully deals with a number of critical issues. I strongly support the fundamental thrust of this order to move the bulk of the market aggressively toward forward contracts and away from an over reliance on the volatile and exorbitantly priced spot markets operated by the ISO and PX. If our order can achieve this goal, it will go a long way toward ensuring just and reasonable prices in California. The over reliance on the spot markets, a feature built in to the California market design, is a glaring flaw that must be corrected, and this order takes bold steps to do so.

I heartily endorse this order's elimination of the existing requirement that the California utilities sell all of their generation, and purchase all of their power needs, through and ISO and PX markets. This so-called buy/sell requirement, again a fundamental feature of the California market, is forcing the utilities to the volatile spot markets. The utilities should have the flexibility to sell their substantial portfolio of generation assets and contracts directly to their end use customers such as homeowners, hospitals and small businesses, thereby bypassing the wholesale market entirely with

these 25,000 MW of assets. As our order points out, this is roughly 60% of the market at peak, and is probably 90% of the market off peak. Under today's order, the California

[1]Nantahala Power and Light Co. v. Federal Power Commission, 384 F.2d 200 (4th Cir. 1967), cert. denied, 390 U.S. 945 (1968); Narragansett Electric Co. v. Burke, 119 R.I. 559, 381 A.2d 1358 (1977), cert. denied 435 U.S. 972 (1978).Mississippi Power & Light Co. v. Mississippi ex rel. Moore, 487 U.S. 354 (1988).

Commission may require the utilities to offer these 25,000 MW at regulated cost of service rates. Inexplicably, the California Commission objects to this provision, yet consumers who have been concerned about over reliance on FERC regulated wholesale markets should know that today's order "defederalizes" no less than 60% of the California market on peak days. In other words, had today's order been in effect over the past summer, fully 60% of generation supply on the hottest day could have been sold at prices capped by the California Commission at regulated cost of service rates. This is a huge pro-consumer change that the California Commission must embrace.

The ISO must have an independent board of directors, although as our order recognizes the State of California has a legitimate interest in ensuring that board members, though independent, are appropriately cognizant of state concerns in addition to regional concerns. Our order offers to work with the State, though appropriate technical conferences devoted to this issue, to ensure that the independent board selection process is structured reasonably with these concerns in mind.

I am pleased that our order sends an unmistakable signal that substantial additional market design changes will be required long term. Early next year our staff will host a technical conference devoted to revamping the market rules that define the manner in which the ISO operates real time markets and prices congestion. Our order specifies that this technical conference will focus on moving the ISO toward locational marginal pricing, security constrained unit commitment dispatch, an installed capacity market, reserve requirements, and demand side response programs. My own view is that the California ISO's market rules should look more like those of PJM. PJM, formerly a tight power pool, is in my judgment the most efficient power market in the country, and the California market should emulate the PJM market design to the extent feasible. Although I would have used stronger language in the order to achieve this result, I am satisfied that our order takes large steps in this direction and sends strong signals about the virtue of a new market design based upon LMP for congestion management and security constrained economic dispatch.

As I have mentioned, I agree with the reaffirmation of our earlier conclusions that prices are not just and reasonable and market power has been exercised. These are important conclusions.

There are a number of areas, however, where I disagree with our order. I would have handled these issues differently. I disagree with the order's language that there is insufficient evidence on the record before us to find specific instances of the exercise of

market power. At this time our staff is in fact in the process of investigating allegations of market power abuses by suppliers, so this conclusion is at best premature. I have been presented no analysis by our staff that would allow me to conclude that specific exercises of market power have not occurred, and in fact an investigation is underway. To the extent that our order implies the contrary, I disagree.

I am not at all enamored with the so-called $150.00 break point. I have deep reservations about whether it will serve a useful purpose and in fact mitigate high prices. I hope that it does, but I doubt it. I would have strongly preferred the imposition of a hard price cap for the spot markets (exempting new generation), calculated on a generator-by-generator basis at each generator's variable operating costs plus a reasonable capacity adder perhaps in the range of $25.00. This would vary over time and would allow each generator to recover its fuel, emission permit and O&M costs, plus a reasonable adder. I come to this conclusion reluctantly, but it is time to staunch the hemorrhaging in the volatile spot markets.

I disagree with the order's assertion that a five year forward contract at a price of roughly $74.00 per MWh is likely to be just and reasonable. The $74.00 figure is intended to be a benchmark price, but to me it would be a much more appropriate figure for a contract of two year's duration rather than a five year contract. I am pleased, however, that the order at least declares that this is not a price floor and that lower price may be justified by the facts of a particular deal.

In this order I would have preferred to open a section 206 investigation into wholesale prices in the entire western interconnection. We have a number of requests before us to do this, based upon the theory which I support that the entire western interconnection is one big machine that ought to be dealt with as a whole. A number of public officials from the Pacific Northwest in particular are very concerned about both the volatility and level of wholesale prices. I share those concerns, and would have opened a formal investigation in this order. I am told by our legal counsel that such a formal investigation is probably a necessary precursor for any type of region-wide price relief.

I am concerned that prices in California were not just and reasonable before October 2 of this year, yet our section 206 authority may prohibit retroactive refunds. Our November 1 order suggested that the parties explore equitable relief, and I would have strongly preferred to use this order to set a date for a settlement conference to before one of our administrative law judges aimed at exploring equitable relief for Californians. This is an important issue that should not be ignored or simply placed on the back burner by this agency.

Finally, I would have used this order to act on PG&E's request for a separate settlement conference to help negotiate forward contracts that would be acceptable to the sellers, purchasing utilities and California Commission. I strongly support such a conference, and recommend that a date be set before one our ALJ's as soon as possible.

We should vigorously pursue this settlement option that will facilitate forward contracting in California.

Therefore , I concur with today's order.

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William L. Massey
Commissioner

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company

v. Docket Nos. EL00-95-000, et al.

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

Investigation of Practices of the California Independent System Operator and the California Power Exchange, et al. Docket Nos. EL00-98-000, et al.

(Issued December 13, 2000)

HÉBERT, Commissioner, *concurring:*

Few can doubt that California, truly, is in the throes of an energy emergency. The ISO struggles daily to procure enough power in the spot market to keep the lights on. Load serving utilities, unable to pass billions of dollars of purchased power costs along to customers, sustain cuts in their credit ratings and threats to their solvency. Wholesale and retail customers experience, or soon threaten to experience, sharp increases in their electricity bills. (This is on top of sharp projected increases in natural gas prices this winter.)

Enter the FERC. California electricity customers – who now know much more about energy supply and regulation than they should be forced to – hope that the Commission will impose restraints on the market for electricity that will ensure that their bills will, hopefully soon, go down. California electricity suppliers – who are increasingly wary of entering uncertain California markets – hope that the Commission will allow markets to operate as competitive markets are supposed to. And California regulators and politicians – who now may wish that they had never pioneered electricity restructuring – turn to the Commission to reform markets that operate in a half-regulated, half-competitive hybrid environment.

Today the Commission issues its final order on reforming California electricity markets. Today's order contains just enough to ensure that everyone who has turned to the Commission for relief will return disappointed in some respect. Undoubtedly, the Commission will be portrayed as the Grinch Who Threatens to Steal Christmas.

To be frank, I too am a little disappointed by today's order. It stops short of ordering those remedies that are truly necessary to promote a competitive electricity market that will, if given a chance, operate to the benefit of all consumers. I view today's order as a missed opportunity. Current emergency circumstances should embolden federal and state regulators – not intimidate them – to take decisive action. Timidity is no longer excusable. California ratepayers will benefit from the restructuring of the California energy market <u>only</u> when the market is allowed to operate without artificial restraints designed by regulators and politicians who believe that they know best how to serve energy customers. The Commission needs to act now to ensure that energy suppliers have an incentive to enter capacity-starved California markets, that local load-serving utilities have strong reason to hedge against price risk, that entrepreneurs have a motivation to develop new products and technologies, and that consumers share a motivation to conserve.

I stated much these same concerns in my concurring statement attached to the Commission's November 1 proposed order in this proceeding. At that time, I explained that, if it were up to me, the Commission's order would be much, <u>much</u> different. I would have adopted some of the remedial measures that the Commission declined to adopt. And I would have refrained from adopting some of the remedial measures that the Commission did adopt.

To summarize briefly, I would have adopted the following remedial measures: (1) eliminate all price controls; (2) abolish the single price auction for bids into the ISO and PX; (3) terminate the mandatory buy-sell requirement in the PX; and (4) direct the ISO and PX to address remaining impediments in their January, 2001 regional transmission organization (RTO) filing. I would not have adopted the following remedial measures: (1) modify the single price auction; (2) disband stakeholders boards of the ISO and PX at this time; and (3) dictate to market participants how best to manage risk. Finally, I stated that the Commission should have been more forthright and candid in its discussion of potential refunds. In particular, I expressed concern that the specter of potential refunds for prices that already have been adjudged to be just and reasonable, within the meaning of the Federal Power Act, will only exacerbate supply deficiencies in California by accelerating the exodus of power outside California.

One and one-half months – long enough for a Presidential election and a five-week recount – have now passed. I still have many of the same concerns that I identified in my November 1 concurrence. For this reason, I continue to concur separately from today's order.

Nevertheless, I am pleased by the direction of the Commission. Today's order is not optimal from my perspective or, I suppose, from the perspective of any other Commissioner. But it represents a balanced, considerate approach that has won the approval of all four Members of the Commission. I thank the Chairman of this Commission for crafting a document that we can now agree will help to move California markets in a direction that will begin to deliver on the promise of restructuring that was made to California customers several years ago.

In particular, I am pleased with the tone of today's order. It states unequivocally that the Commission is committed to moving forward, not backward. It recognizes candidly that California energy customers have been suffering in recent months. It also recognizes that the solution to this suffering is to promote the evolution of truly competitive markets. Key to this competitive evolution, the order explains, is the introduction of electricity supply into California. For example, the Commission today states that "[w]e cannot afford to stymie entry and we therefore chose to err on the side of relying on the market to set the scarcity price subject to our monitoring rather than depressing prices and running the risk that much needed supply goes elsewhere." The Commission also states that "[t]he one thing that California needs most is new supply and a return to traditional cost of service ratemaking will not encourage supply to enter the California market." Other passages similarly emphasize the Commission's commitment to promoting supply.

I still oppose the $150 "breakpoint" proposed in November and ratified in today's order. I still believe -- especially so after reviewing the comments on this point -- that the breakpoint will operate as a soft cap that will stifle the entry of generation into California markets. This is precisely what California does not need. As the Commission states in one short sentence, with remarkable clarity and conciseness that is rarely found in Commission orders, "Price caps will stifle needed entry." If the Commission were true to its words, it would take the initiative now to eliminate the breakpoint and any other measure, whether hard, soft, or in-between, that threatens to inhibit generation entry and the precarious reliability of the California grid.

If the Commission must insist on a breakpoint, I would (initially) set it at the existing $250/MWh figure. Any hesitation on this point should be eliminated by the action the Commission took just last week. In response to an emergency plea from the

ISO, the Commission accepted a tariff amendment that replaced the existing $250 hard cap with a $250 soft cap, modeled after the Commission's proposed breakpoint. In approving this revision, the Commission adopted the ISO's explanation that a higher, softer cap is necessary: (1) to allow generators to recover their operating costs; (2) to better enable the ISO to procure desperately needed generation resources; and (3) to maintain the reliability of the transmission system. Today's order makes no effort to reconcile the two orders.

I also would insist on some type of escalator provision if I were convinced the breakpoint would remain in effect for an extended period of time. In my concurrence from the November 1 proposed order, I explained my preference for the breakpoint figure to escalate upward by specific amounts (say, $250 or $500 amounts) at specific intervals (say, every six months). In this manner, California market participants and institutions, in conjunction with California regulators and legislators, would have the incentive to respond immediately to the market design flaws identified by the Commission. Testimony from consumer groups at our public conference in this proceeding, held on November 9, 2000, in Washington, D.C., supported such an approach.

However, I no longer have any reason to insist on such an escalator. Today's order is clear that the $150 soft cap will remain in effect for only four months. Specifically, the order explains that the breakpoint will cease at the end of April. At that time, the Commission's interim monitoring of breakpoint information will be replaced by a comprehensive monitoring and mitigation program developed by market participants, working with the assistance of Commission staff. I appreciate the effort of the Commission today to promote cooperative, market-determined solutions – rather than advance unilateral governmental solutions – to identified market problems.

Moreover, I appreciate the resolve of the Commission to resist the entreaties of commentators who wanted to lower the cap, harden it, regionalize it, index it, load-differentiate it, or tie it to cost. These are difficult decisions for the Commission. Emotions run high on this topic, and pressure is intense. Today, the Commission stands united that competitive energy markets remain the goal and that competitive markets require simplicity and transparency – not additional government-imposed obstacles. The fact that the cap goes away in four months tells the politicians in California to remove impediments to supply immediately. If such impediments are not removed, the people of California should know precisely where to place the blame.

I applaud another feature of today's order. I worried in my November concurrence that the specter of after-the-fact price correction would scare energy suppliers out of

California markets. Most of all, market participants want consistency and certainty. The type of capital investment that California needs requires a degree of assuredness that the Commission, to date, has been reluctant to offer. The hard-working people of California deserve that assurance in order to have reasonably priced electricity that never must be turned off because of shortages.

I am pleased to state that the Commission now recognizes the need for greater certainty in electricity pricing. Specifically, the Commission now intends to close its review of bids into the ISO real-time market after 60 days. If generation sellers have not received notification from the Commission within 60 days, refund liability will automatically end. In a similar light, today's order also explains that all bids -- even those in excess of $150 -- will not later be reduced if they simply reflect the higher cost of generation inputs and the true cost of scarcity. These limitations -- reserving "price mitigation" for real exercises of market power rather than focusing on price level itself -- represent an impressive contribution to the Commission's basket of remedial measures.

I am also pleased that the Commission has carved out a role for the State of California in selecting the new Governing Board for the ISO. In my November 1 concurrence, I stated concern that the Commission needlessly was provoking a constitutional show-down by deciding for itself how best to reconstitute the stakeholder board of the ISO – without seeming regard for the legislative design of that board. I have no particular fondness for the stakeholder board, which has demonstrated itself to be incapable of prompt and truly independent decision-making. But I had even less fondness for the Commission's decision to dictate little, if any, role for state officials and interested market participants in the selection of a new Board.

Today's order rectifies this problem. Specifically, it establishes procedures to discuss with state representatives the appropriate role for the State of California in the selection of the new Board. Moreover, today's order corrects a glaring omission from the November 1 order, by recognizing that the upcoming RTO filing by the ISO is the appropriate vehicle for assuring the independence of the Governing Board. In this manner, today's order appropriately places the Commission primarily in a reviewing role, rather than a drafting role, in the selection of a new Board.

There are, of course, many other provisions in today's order that are worthy of comment. Mercifully, I will refrain from additional comment on all of the remaining provisions save one. That provision is the Commission's decision today to establish a benchmark price for wholesale bilateral contracts.

I agree wholeheartedly with my colleagues that the Commission must act to move load from volatile spot markets run by the ISO and PX to long-term forward markets. As today's order explains, energy suppliers and customers can best insulate themselves from price instability, and thus hedge against risk, by executing long-term bilateral contracts outside the ISO and PX. That is why I favor the Commission's decisions to: (1) eliminate the obligation of investor-owned utilities to sell all of their generation into, and buy all of their generation from, the PX; and (2) terminate the PX's wholesale rate schedules.

I nevertheless have reservations about the Commission's decision to go one step farther and to establish a benchmark for long-term wholesale contracts. I have trouble understanding what purpose the benchmark will serve in practice. The Commission has no reason to presume the reasonableness of long-term prices at or below the benchmark. This is because all long-term sales by public utility suppliers must be made under market-based sales tariffs that already have been approved by the Commission. Thus, all long-term sales, whether priced at a figure below, at, or even above the benchmark already have been adjudged to be reasonable. Moreover, the $74 benchmark figure is close to arbitrary; it is based on historical numbers and may have little actual relevance to market conditions now and in the future.

However, I do understand what the Commission is trying to accomplish. In establishing a benchmark, it is attempting to motivate the California Commission to adopt its own benchmark and safe harbor for generation purchases by California utilities. As today's order, as well as recent headlines, make clear, California has at its disposal right now a solution to much, if not all, of its supply woes. Wholesale suppliers and customers alike want to lock in stable, multi-year prices for electricity. They are ready to execute contracts. What is holding them back is the historic eagerness of the California Commission to second guess long-term purchase decisions and to determine, on the basis of currently prevailing prices, whether past purchasing decisions were prudent.

I hope that the California Commission follows our suggestions on necessary market reforms. It is that Commission – not the FERC – that now holds the ultimate power to end the electricity crisis that now looms over California. California's concern for price is understandable. It justifiably might think that California utilities might cut better, lower-priced deals in later months or years. However, at this critical juncture, California's principle concern must now be supply. The state must now take immediate action to free up supply for California customers by informing willing sellers and buyers – right now – that long-term sales at reasonable, historically-justified prices are acceptable (if not preferable). This is the only real way to mitigate exposure to high, volatile prices in the spot market.

It deeply bothers me when I see pictures of the California State Christmas tree standing unilluminated at night. My bother turns to great sadness when California customers confront bills they cannot afford and must make grievous choices affecting their lives and businesses. The FERC has now done what it must. I hope the CPUC and the State of California act in kind as well.

In the spirit of this holiday season, FERC puts its hands out to the great people of California and, I hope and pray, the leaders of that great state will deliver the goods. It is a gift Californians deserve.

For all of these reasons, I respectfully concur.

Curt L. Hébert, Jr.
Commissioner