

COMM-OPINION-ORDER, 93 FERC ¶61,121, **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 No. . . ., (Nov. 01, 2000)

**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 No. EL00-95-000, **Investigation of Practices of the California Independent System Operator and the California Power Exchange**, Docket No. EL00-98-000, **Public Meeting in San Diego, California**, Docket No. EL00-107-000, **California Power Exchange Corporation**, Docket No. ER00-3461-000, **California Independent System Operator Corporation**, Docket No. ER00-3673-000

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**California Independent System Operator Corporation**, Docket No. ER00-3673-000

**Order Proposing Remedies for California Wholesale Electric Markets**

[61,349]

(Issued November 1, 2000)

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

#### Table of Contents

Introduction and Summary

Background

A. *California Restructuring*

B. *Events of Summer 2000*

C. *Commission Actions in Response*

D. *Docket No. ER00-3461-000*

E. *Docket No. ER00-3673-000*

Interventions and Other Pleadings

Procedural Matters

## Discussion

### A. Overview

### B. Proposed Immediate Measures

#### 1. Requirement to Sell into and Buy from the PX

##### 2. Underscheduling of Load and Resources

##### 3. Governance of the PX and ISO

##### 4. Interconnection Procedures

### C. Longer-Term Measures

#### 1. Reserve Requirement

##### 2. Alternative Auction Mechanisms

##### 3. Balanced Schedules

##### 4. Enhanced Market Mitigation

##### 5. Congestion Management Redesign

##### 6. Demand Response Program

##### 7. Importance of RTO Development and Compliance

### D. Price Mitigation and Refunds

#### 1. Price Mitigation Measures

##### 2. Refund Liability of Public Utility Sellers in the ISO and PX Markets

### E. Docket Nos. ER00-3461-000 and ER00-3673-000

### F. Actions Others Should Take

#### 1. Offering a Full Menu of Forward Products

##### 2. Additions of Generation and Transmission Capacity

##### 3. Demand Response

##### 4. Elimination of Impediments to Forward Contracting

Hearing Based on Written Submissions and Oral Presentations to the Commission

### Introduction and Summary

On August 23, 2000, the Commission issued an order in Docket Nos. EL00-95-000 and EL00-98-000,

initiating hearing proceedings under Section 206 of the Federal Power Act (FPA) to address matters affecting bulk power markets and wholesale energy prices in California.<sup>1</sup> The Commission held the hearing in abeyance, however, pending the results of a separate staff fact-finding investigation, ordered by the Commission on July 26, 2000, of the conditions in electric bulk power markets (including volatile price fluctuations) in various regions of the country.<sup>2</sup> The Commission has now had the opportunity to analyze the staff investigation report (Staff Report) as it pertains to California and the Western region, and has placed that report in the record of this proceeding. Based on that report, as well as other submissions in these dockets<sup>3</sup> and the Commission's experience in dealing with evolving California market issues in over 85 Commission orders since the time the restructured California markets began operation in 1998, and based on the seriousness of market dysfunctions and recent pricing abnormalities in California, in this order the Commission is 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 Commission finds in this order 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, 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.

#### **[61,350]**

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. Under such conditions, the Commission is obligated under FPA Section 206 to take action to establish market rules, regulations and practices that will ensure just and reasonable rates in the future.<sup>4</sup> Accordingly, we herein propose fundamental modifications to the wholesale market structure and rules currently in place in California; we also propose price mitigation measures to ensure that wholesale rates remain just and reasonable during the period it will take to effectuate the market structure and market rule changes being proposed. Rates charged by public utilities for sales into the ISO's markets and into the PX's day-ahead and hour-ahead markets will remain subject to the refund conditions set forth in the August 23 Order, as discussed more fully below.<sup>5</sup>

In developing the proposed remedies in this order, the Commission's goal has been 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. We believe that a well functioning competitive wholesale power market in California, which includes a well functioning regional transmission grid, is a fundamental part of the solution to the supply problems and price volatility in California. The interstate, wholesale nature of electric markets in California and adjoining states makes it incumbent that we take whatever steps we can to make markets in the region work for the ultimate benefit of consumers—assuring a reliable supply of energy at the lowest reasonable rate.

The Commission has also had to grapple with a number of issues that involve the line between State-Federal jurisdiction. There are two aspects to this. First, many, but not all, of the defects in the California markets are within this Commission's jurisdiction. However, certain matters significantly affecting the operation of the wholesale as well as the retail markets in California are within the jurisdiction of the State of California. We therefore include in this order a discussion of matters that need to be corrected by State regulators if there are to be competitive, well functioning markets in California, and if California consumers are to be protected in the future. We urge the State to continue working to address these matters within its jurisdiction as expeditiously as possible. Second, during the past several years this Commission has struggled to accommodate, and where possible defer to, the State's initial decisions on restructuring, including its decisions directly impacting matters within our exclusive jurisdiction under the FPA. However, we have reached a point where we must make some difficult choices with respect to matters

within our exclusive jurisdiction, and we conclude that certain defects in wholesale markets must be remedied even if our decisions preempt certain decisions previously made by the State in its initial restructuring legislation and orders. Unless we take these steps, we believe we will be abdicating our responsibility under the Federal Power Act to ensure just and reasonable rates and service by public utility sellers of wholesale energy in California.

The immediate remedies proposed in this order include:

- the elimination of the requirement that the three investor-owned utilities (IOUs)--Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SoCal Edison), and San Diego Gas & Electric Company (SDG&E)--must sell into and buy from the PX;
- the addition of a penalty charge for deviations in scheduling in excess of five percent of an entity's hourly load requirements and the disbursement of penalty revenues to the loads that scheduled accurately;
- the establishment of independent, non-stakeholder Governing Boards for the PX and the ISO; and
- the establishment of generation interconnection procedures.

[61,351]

We also identify a number of structural reforms that must be addressed, including:

- the submission of a congestion management redesign proposal;
- possible changes to the auction mechanisms;
- improved market monitoring and market mitigation strategies;
- demand response programs by the ISO and Scheduling Coordinators;
- elimination of the requirement for balanced schedules; and
- new approach to reserve requirements.

To ensure fair prices while these market reforms are being put in place, the order proposes additional temporary measures to mitigate prices, including modification of the single price auction so that bids above \$150/MWh cannot set the market clearing price that is paid to all bidders; imposition of comprehensive reporting and monitoring requirements for sellers bidding above \$150/MWh; and retention of a refund remedy for sales from October 2000 through December 2002.

The order also recognizes that, to resolve the problems facing California consumers, the Public Utilities Commission of the State of California (California Commission) and others must address the following issues:

- delays in siting additions of generation and transmission capacity;
- implementation of additional demand response programs at the retail level; and
- elimination of impediments on Load Serving Entities pursuing power supplies on a forward basis.

The Commission has concluded that the hearing we ordered on August 23 does not need to be a trial-type hearing. Rather, the issues raised in this proceeding can be resolved based on written comments and evidence and oral presentation directly to the Commission. The Commission will permit all interested persons that have not already intervened in these dockets to intervene, and allow all interested persons to file comments on the proposed remedies and any additional information or evidence, by November 22,

2000. We also will hold a public conference on November 9, 2000, which will provide interested persons the opportunity to discuss the proposed remedies before the Commission.

## *Background*

### *A. California Restructuring*

Efforts to restructure the California electric industry began in 1994 in response to high electricity prices.<sup>6</sup> Extensive hearings and negotiations in proceedings before the California Commission resulted in a final restructuring order issued in December 1995<sup>7</sup> and led to the unanimous enactment of Assembly Bill 1890 by the California legislature in September 1996.<sup>8</sup> The main points of AB 1890 included: (1) creation of an ISO and PX by January 1998 and simultaneous initiation of direct access; (2) creation of the California Electricity Oversight Board (Oversight Board) with members appointed by the Governor and legislature;<sup>9</sup> (3) a competitive transition charge (CTC) for the recovery of the IOUs' stranded costs; and (4) a 10 percent rate reduction for residential and small customers, and a rate freeze for all retail customers.

PG&E, SoCal Edison, and SDG&E submitted filings to this Commission in April 1996 seeking approval for those aspects of the restructuring subject to FERC's jurisdiction, namely, the conveyance of operational control of transmission facilities to the ISO,<sup>10</sup> the authority to sell energy at market-based rates through the PX, and approval of the overall

**[61,352]**

framework for establishment of the ISO and PX, and for the jurisdictional split between the transmission and local distribution facilities of the utilities. In a series of orders issued that Fall, the Commission largely accepted the filings, and provided a preliminary assessment of the adequacy of the utilities' market power analyses.<sup>11</sup>

In March 1997, the ISO and PX submitted filings constituting Phase II of the restructuring proposal, consisting of organizational and governance documents and an Operating Agreement and Tariff for each, a Transmission Control Agreement, and other materials and explanations required by the Commission in earlier orders. In response to a July 30, 1997 Order by the Commission directing the ISO and PX to file restated Tariffs, Agreements and Appendices, they submitted on August 15, 1997 filings with numerous additional materials. The Commission addressed these filings in an order dated October 30, 1997, conditionally authorizing limited operation of the ISO and PX.<sup>12</sup> Since the ISO and PX have commenced commercial operations, the Commission has devoted significant resources to many proceedings involving the ISO and PX, including 30 separate amendments to the ISO's tariffs to address, in large measure, the difficulties faced by the ISO in implementing the requirements imposed by AB 1890 and the California Commission.<sup>13</sup>

Shortly after the ISO and PX commenced operations on March 31, 1998, the ISO witnessed dramatic spikes in the price for certain ancillary services, and did not receive sufficient bids for others, events that were inconsistent with the operation of efficient markets.<sup>14</sup> After analyzing reports prepared by market monitoring committees and comments from numerous parties, the Commission, among other things, directed the ISO to file a comprehensive proposal to redesign its Ancillary Services markets.<sup>15</sup> This redesign has been implemented over a period of 24 months, and certain elements have yet to be proposed to the Commission for approval.<sup>16</sup>

The ISO sought price caps as a solution for the volatility and thinness in its Ancillary Services markets. In the July 17, 1998 Order, we authorized the ISO to reject bids in excess of whatever price levels it believed were appropriate for the ancillary services it procures. On rehearing, we explained that, as the procurer of ancillary services, the ISO had the discretion to reject excessive bids. We also stated that a purchase price cap is not an ideal approach to operating a market and that we did not expect the cap to remain in place on a long-term basis.<sup>17</sup> In order to make the Imbalance Energy market similarly situated to the Ancillary Services markets, we later authorized the ISO to adopt a purchase price cap for its Imbalance

Energy market at whatever level it deemed necessary and appropriate.<sup>18</sup>

In our order approving the ISO's Ancillary Services market redesign proposal, we allowed the ISO to retain its authority to specify purchase price caps for Ancillary Services and Imbalance Energy until November 15, 1999.<sup>19</sup> The ISO had proposed to raise and eventually eliminate existing price caps on Ancillary Services and Imbalance Energy upon the implementation of several redesign elements, but in the interim, it planned to maintain the current \$250 price caps. The ISO had also proposed a safety net in which it would continue to monitor the markets, and if it identified market failures or supply insufficiencies, it would lower price caps in the affected markets. We directed the ISO to eliminate the price caps by November 15, 1999, with the caveat that the ISO

**[61,353]**

could file for an extension of its price cap authority if its experience with the market reforms over the summer indicated serious market design flaws still existed.

On September 17, 1999, the ISO filed proposed tariff revisions to extend for one year, until November 15, 2000, its authority to cap Ancillary Services and Imbalance Energy prices. By direction of the ISO's Governing Board, the price caps were raised from \$250 to \$750, effective September 30, 1999. The proposal gave the ISO the discretion to lower the price caps to \$500 effective June 1, 2000, if the ISO Governing Board determined that any of three specific conditions were met. The proposal also gave the ISO discretion to lower the price caps by an unspecified amount in the event that it determined that the markets were not workably competitive. The Commission accepted the proposed tariff provisions.<sup>20</sup>

#### *B. Events of Summer 2000*

Wholesale electricity prices in California jumped dramatically higher this summer with particularly high peaks during the periods May 21-24, June 12-16, and June 26-30. The price spikes affected all markets run by the PX and the ISO. The monthly average unconstrained market-clearing price (UMCP) for May in the PX's day-ahead market represented a 100 percent increase over May 1999.<sup>21</sup> The PX's constrained day-ahead price (NP15) peaked at \$1,099/MWh on June 28, 2000.<sup>22</sup> Prices in the ISO's real-time market neared or reached its \$750 cap twice in May and on 8 occasions in June. The ISO lowered the price cap from \$750 to \$500 on July 1, 2000. Subsequently, on August 7, 2000, the ISO further reduced the purchase price cap to \$250 per MWh.

High temperatures and generation outages led the ISO to declare system emergencies 39 times between May and August. PG&E had to effect rolling black-outs in San Francisco area on June 14. Notably high prices were also experienced at trading hubs throughout the Western Interconnection. During this summer period, costs of electricity inputs began to increase, particularly gas costs at the California border which rose from \$2/MMBtu in the spring to about \$6/MMBtu this summer. At the same time, existing gas fired units<sup>23</sup> were operated at unprecedented levels, driving up the price of NOx emission allowances from around \$6/lb to over \$40/lb at the end of August.<sup>24</sup>

Because the retail rate freeze imposed in SDG&E's service area by AB 1890 ended in 1999, the very high wholesale prices were passed through directly to the utility's retail customers, resulting in monthly bills that were up to 200 to 300 percent higher than the prior year. PG&E and SoCal Edison, still subject to retail rate freezes, report that their cost for wholesale power has exceeded the amount recovered in retail rates by billions of dollars.<sup>25</sup>

These events have created an environment of distress in the State. Probes have been initiated by the California Commission, the Oversight Board, and California's Attorney General, in addition to the investigation by this Commission discussed below. In August, the California Commission put in place a temporary retail rate cap for certain small customers of SDG&E, limiting the amount that they must pay per month. Subsequently, the California legislature enacted AB 265, a retroactive retail cap which expands on the California Commission's action. The legislation limits San Diego residential customers' rates to 6.5

cents per kWh, and requires the California Commission to investigate the purchasing practices of SDG&E. Both retail rate caps defer payment of the total amount due to the utility, requiring customers to pay the balance of costs paid into the wholesale market with interest in the year 2003.

California's Governor also signed SB 970 into law in early September, which will streamline regulatory approval for new power plants.<sup>26</sup> A number of other bills encouraging energy efficiency, distributed generation technologies and approval of new generation were also enacted.<sup>27</sup>

#### **[61,354]**

The ISO and PX and the ISO's Market Surveillance Committee (MSC) analyzed the pricing anomalies experienced during the summer and came to similar conclusions. A preliminary report prepared by the PX dated September 29, 2000, found that price spikes were caused by flawed market structures and an insufficient supply of power, rather than gaming by market participants. Although market conditions created the potential for abuses of market power, the PX Report indicated that no one group of participants was setting prices. The ISO, similarly, reported that during certain operating conditions, suppliers can have significant market power, although the underlying causes of high prices were structural and operational in nature.

#### *C. Commission Actions in Response*

On July 26, 2000, the Commission issued an order directing a staff fact-finding investigation of the conditions in electric bulk power markets (including volatile price fluctuations) in various regions of the country.<sup>28</sup> The order asked staff to determine any technical or operational factors, regulatory prohibitions or rules (Federal or State), market or behavioral rules, or other factors affecting the competitive pricing of electric energy or the reliability of service, and to report its findings to the Commission by November 1, 2000. Later, staff was asked to expedite the investigation as it related to California and markets in the Western Interconnection.

On July 28, 2000, the Commission issued an order in [Docket No. EL00-91-000](#) in response to a complaint filed by Morgan Stanley Capital Group Inc. against the ISO, asking the Commission to invalidate the ISO's decision to lower the maximum price it was willing to pay to sellers of imbalance energy and ancillary services. At the time the Morgan Stanley request was filed, the ISO Governing Board had voted to lower the ISO's maximum purchase price for these services from \$750 to \$500. Morgan Stanley wanted the Commission to reinstate the \$750 purchase price cap and prevent the ISO Board from further reducing the cap. The Commission denied Morgan Stanley's request, finding that the ISO's maximum purchase price authority remained acceptable because the ISO did not have the authority to require sellers to bid into its markets, and thus, could not dictate sellers' prices.<sup>29</sup>

On August 2, 2000, SDG&E filed a complaint in [Docket No. EL00-95-000](#) against all sellers of energy and ancillary services into the ISO and PX markets requested, among other things, that the Commission impose a \$250 price cap. The August 23 Order denied SDG&E's request because the company had not provided sufficient evidence to support an immediate seller's price cap.<sup>30</sup> However, 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 in the California ISO and PX markets, and also to investigate whether the tariffs, contracts, institutional structures and bylaws of the ISO and PX are adversely affecting the efficient operation of competitive wholesale power markets in California and need to be modified.

On September 12, 2000, the Commission conducted a public meeting in San Diego to allow interested persons to give the Commission their views on recent events in California's wholesale markets; written comments were accepted in [Docket No. EL00-107-000](#). In addition, members of the Commission and staff participated in a number of Congressional hearings and proceedings conducted by California State authorities throughout the summer.

The staff fact-finding investigation is now completed, and the Staff Report has been placed in the official record of this proceeding. The Staff Report is generally consistent with the findings of the PX and ISO reports. A detailed summary of the Staff Report is attached to this order as Appendix D.

Briefly, the Staff Report identifies three factors that contributed to the high prices experienced in California this summer. First, competitive market forces played a major role in the run-up of prices through 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.

In addition, the Staff Report concludes that existing market rules along with some flawed retail regulatory policies exacerbated the situation. The Staff Report notes that the requirement placed upon the three IOUs by the California Commission to buy and sell all their energy needs through the PX, coupled with the California Commission's restrictions on their ability to forward contract, exposed the three IOUs to the volatility of the spot market without the ability to mitigate this summer's price volatility. The Staff Report also notes that a lack of demand responsiveness on the part of

[61,355]

retail load allows prices to rise well above competitive levels when demand is high and supplies are scarce. Finally, the Staff Report finds that the ISO's policies relating to replacement reserves increased the amount of demand and supply that appears in the ISO's real-time market (underscheduling in the PX), which results in operational and reliability problems for the ISO and increased costs. The Staff Report recommends that the Commission eliminate these flawed market rules.

Lastly, the Staff Report notes that there is evidence suggesting that sellers had the potential to exercise market power (where market power is defined as prices above short-run marginal cost) this summer; however, the data analyzed in the Staff Report and the limited time available were not sufficient to make determinations regarding the exercise of market power by individual sellers.<sup>31</sup> One of the Staff Report's proposed changes to the market rules would eliminate the single price auction rule.<sup>32</sup>

D. [Docket No. ER00-3461-000](#)

On August 22, 2000, the PX filed Tariff Amendment No. 19 in [Docket No. ER00-3461-000](#), proposing to impose maximum prices on Demand and Supply Bids in its Day-Ahead and Day-of Markets of \$350/MWh. The PX states that the \$350/MWh limit represents the sum of the \$250/MWh price limitation on ISO purchases of Imbalance Energy plus the \$100/MWh amount the ISO pays for Replacement Reserves. The PX also states that the establishment of equivalent maximum prices in both the ISO and PX markets will remove any possible uncertainty that might potentially encumber the operation of either of these markets. The PX requests that Amendment No. 19 be granted the earliest possible effective date but no later than sixty days after filing. By letter dated October 5, 2000, Commission staff requested, within fifteen days, additional information from the PX to support the need for their proposed caps. On October 19, 2000, the PX filed additional information (PX Deficiency Report) analyzing six months of recent PX market data demonstrating that the ISO's real-time market serves as a *de facto* price cap in the PX day-of markets. Two exceptions occurred on June 27 and June 28.

Notice of the PX's filing was published in the *Federal Register*, 65 *Fed. Reg.* 57,599 (2000), with motions to intervene and protests due on or before September 12, 2000. The California Commission filed a notice of intervention. Timely motions to intervene, comments, and protests were filed by the entities listed in Appendix A. In addition, Williams Energy Marketing & Trading Company (Williams) and the Oversight Board filed untimely motions to intervene.

The California Commission, the Oversight Board, PG&E, and SoCal Edison support the filing and request its approval as an interim measure until additional steps are taken to restore prices to just and reasonable levels. Other intervenors argue that the filing should be rejected because: (1) the PX has

provided virtually no justification for its proposed price cap; (2) the proposal would further intrude into the competitive energy markets and should be deferred; and (3) the PX's proposal is inconsistent with the Commission's findings in *Morgan Stanley*. Power marketers also argue that price caps are unnecessary and harmful to the development of a competitive electric market by jeopardizing investment in generation and creating an atmosphere of extreme uncertainty.

E. [Docket No. ER00-3673-000](#)

On September 14, 2000, the ISO filed Tariff Amendment No. 31 in [Docket No. ER00-3673-000](#), proposing to remove the November 15, 2000 termination date of the ISO's purchase price cap authority. The ISO states that the proposed Amendment No. 31 would remove the existing termination date of the ISO's authority to disqualify Ancillary Service and Imbalance Energy bids that exceed levels specified by the ISO and would confirm the ISO's authority to establish bid caps for all of its markets. The proposed amendment does not specify the particular level of the purchase price caps; instead, it preserves the discretion of the ISO to adjust the bid cap levels as appropriate. The ISO requests that Amendment No. 31 become effective as of the date the existing provision for bid cap authority expires on November 15, 2000.

Notice of the ISO's filing was published in the *Federal Register*, 65 *Fed. Reg.* 57,599 (2000), with motions to intervene and protests due on or before October 5, 2000. The California Commission filed a notice of intervention. Timely motions to intervene, comments, and protests were filed by the entities listed in Appendix B. In addition, the City of San Diego

[61,356]

(San Diego) filed an untimely motion to intervene.

Eight intervenors filed comments supporting the amendment to extend the ISO's bid cap authority, stating that because the market is not currently workably competitive, purchase caps are necessary. Twelve intervenors protest Amendment No. 31, stating that purchase price caps and the indiscriminate lowering of such caps threatens reliability, creates massive instability, and discourages investment in and development of new generation resources. In addition, these intervenors object to the ISO's proposal to set bid caps and as a corollary reject bids above the cap, instead of setting a purchase price at which they are willing to buy. Intervenors maintain that such an ability to reject bids would lead to the unilateral ability of the ISO to reduce the generator's bid to the price it is willing to pay, and amounts to setting the seller's price in violation of our precedents. Finally, intervenors state that the ISO has not developed specific criteria for the application and level of purchase price caps.

On October 20, 2000, the ISO filed an answer arguing that the protests lack merit.

*Interventions and Other Pleadings*

As noted in the August 23 Order, any party that intervened in [Docket No. EL00-95-000](#) is considered to be a party in this consolidated hearing proceeding.<sup>33</sup> The following filed motions to intervene out-of-time in [Docket Nos. EL00-95-000](#) and/or [EL00-98-000](#): the Cogeneration Association of California jointly with the Energy Producers and Users Coalition (CAC/EPUC); the Cities of Anaheim, Azusa, Banning, Colton, and Riverside, California (Southern Cities); the City of Vernon, California, (Vernon); San Diego; the California Large Energy Consumers Association (CLECA); and Puget Sound Energy, Inc. (Puget Sound).

On October 16, 2000, PG&E, SoCal Edison, and The Utility Reform Network (TURN) (collectively, Joint Movants) filed a joint motion for emergency relief and further proceedings. Joint Movants request that the Commission: (1) make an immediate finding that California's electricity markets are not producing just and reasonable rates; (2) put in place an interim \$100/MWH price cap; (3) direct public utility sellers to provide cost-of-service information for the purpose of implementing market power mitigation measures; and (4) institute expedited procedures to develop long-term market power mitigation measures and to determine refund responsibility. SDG&E filed comments in support of the motion, but urging that

fundamental reforms proceed expeditiously.

The California Commission also filed a motion for interim relief, on October 19, 2000, proposing that FERC require certain generators and marketers to offer specified amounts of capacity under forward contracts at FERC-approved cost-based rates. The following day, the ISO submitted a proposed offer of settlement to impose: (1) a \$100/MWh price cap with a list of exceptions; (2) requirements for load-serving entities to forward contract; and (3) charges against load and generation not adhering to forward scheduling requirements.

Various entities have filed motions and pleadings proposing their own preferred remedies and mitigation such as a \$100 bid cap, reintroduction of cost-based rates, and tiered bid caps.<sup>34</sup> Our decision is informed by these requests and proposals and we incorporate into our actions the aspects of those proposals which achieve our objectives. We inform these parties that they should renew in their November 22 comments any concerns stemming from our decision to propose these remedies.

#### *Procedural Matters*

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 the untimely, unopposed motions to intervene of CAC/EPUC, Southern Cities, San Diego, Vernon, CLECA, and Puget Sound. Appendix C lists all parties to this proceeding. In addition, the Commission will permit all interested persons that have not already intervened in these dockets to intervene and file comments by November 22, 2000.

Also, in view of the early stage of the proceeding and the absence of any undue prejudice or delay, we find good cause to grant Williams' and the Oversight Board's late interventions in [Docket No. ER00-3461-000](#), and San Diego's late intervention in [Docket No. ER00-3673-000](#).

We will reject the ISO's answer in [Docket No. ER00-3673-000](#) to the extent that it represents an impermissible answer to protests. See [18 C.F.R. §385.213](#) (a)(2) (2000).

#### *Discussion*

The Commission is obligated under the FPA to ensure that the rates, terms and conditions

**[61,357]**

of wholesale sales and transmission in interstate commerce by public utilities are just, reasonable and not unduly discriminatory or preferential. Under Section 206 of the FPA, if the Commission finds that rates, charges or classifications for jurisdictional services, or rules, regulations, practices or contracts affecting such rates or charges, are not just and reasonable, or are unduly discriminatory or preferential, the Commission must determine the just and reasonable rate, charge, classification, rule, regulation or practice to be in effect. In exercising this responsibility in today's electric industry environment, the Commission is faced with electric markets that are increasingly interstate in nature and increasingly dependent upon one another, and with markets that are in varying stages of transition to competition at the wholesale and, in numerous states, the retail level. With respect to California, we are faced with a complex transition from one regulatory regime to another and efforts to establish competitive markets at both the wholesale and retail levels. In this particular proceeding, our responsibility is to determine whether public utility sellers to the ISO and PX are charging unjust and unreasonable rates, and whether the market structures and market rules governing public utility wholesale sellers in California, and affecting the wholesale rates of such public utility sellers, are resulting in, or have the potential to result in, wholesale rates that are unjust, unreasonable, unduly discriminatory, or preferential. In particular, we are concerned about whether these market structures and rules, particularly in conjunction with an imbalance of supply and demand, may give public utilities the ability to exercise market power and thereby charge unjust and unreasonable rates.

Before discussing the specific aspects of market structure and rules that may be adversely affecting

wholesale rates, we believe it is important to provide an overview of the historical context in which we address these issues. In 1996, when California decided to embark on its bold and innovative restructuring initiative, it did so because it recognized the problems inherent in its existing regulatory model. Prices paid by retail consumers were among the highest in the nation. California was becoming increasingly dependent on out-of-state generating resources to meet the needs of its citizens. It was against this backdrop of existing problems that California decided to pursue a more market-oriented approach to the provision of retail electricity service--ordering its three IOUs to divest ownership of their generation assets, requiring that they turn over operational control of their transmission facilities to the ISO, establishing the centralized power exchange, and adopting a market design with elaborate rules to govern the behavior of participants in this newly created electricity market.

Although well intentioned, and in some ways visionary, California's pioneering of retail electricity restructuring has not always produced a result that its architects intended--electricity prices lower than historical levels for retail consumers. Indeed, the deregulatory approach adopted by California not only failed to address many of the existing problems which were plaguing the State, but in many ways it exacerbated and magnified those problems. This is not meant to cast blame, but to recognize and try to learn from some of the mistakes that were made. At the Federal level, we remain convinced that competitive markets will provide efficiencies and lower electricity prices to consumers--both retail and wholesale. But such markets need to be properly designed and administered in an independent and non-discriminatory fashion, and they must recognize and accommodate the regional, interstate nature of electricity trade.

The events of this summer provide dramatic evidence of the interstate nature of electric systems and markets in the Western Interconnection. California is not an electrical island. Operationally, the transmission facilities currently controlled by the ISO are part of the much larger Western Interconnection.<sup>35</sup> The reliability of California's electric system depends on access to generating resources located throughout the Western Interconnection.<sup>36</sup> Decades ago, western utilities made large investments in high voltage interstate transmission lines to support the market efficiencies resulting from seasonal diversities between the northern and southern markets. 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.<sup>37</sup> This summer, exports from California to others increased. Therefore, the operation of the California electricity market can affect

[61,358]

prices throughout the entire Western Interconnection. The Staff Report demonstrates that during the summer of 2000 correlations between PX prices and Western market bilateral prices were quite strong.<sup>38</sup>

We make these observations to provide some context for the actions we are proposing in this order. We commend and continue to support California's efforts at restructuring its electricity markets to try and bring lower prices to consumers in California. Although California's restructuring initiatives directly implicated matters subject to our jurisdiction, in order after order, we have deferred wherever possible to the restructuring decisions made by the State. We have devoted unprecedented resources to try and make the California initiative a success. Ultimately, however, the Commission must ensure that wholesale market rules and institutions--even those created by state action--result in just and reasonable wholesale rates for electricity. This summer's events in California and our subsequent investigation have convinced us that we must take decisive action under Section 206 of the Federal Power Act to remedy fundamental problems that have been identified in the California market design. The California experience has highlighted the dangers of hard-wiring a market design that is inflexible and cannot adapt to needed changes.

It is important to get the fundamentals right and to devise a roadmap that takes into account the needs of the market and the regional implications of electricity trade. In many ways, this is the approach that [Order No. 2000](#) has taken with regard to the formation of Regional Transmission Organizations. But [Order No. 2000](#) avoided being overly prescriptive and even went so far as to adopt a requirement of open architecture to ensure that RTOs could adapt and evolve to meet the changing needs of the marketplace. Market rules

and institutions need to be flexible so that they support the natural evolution of the marketplace. In California, we are confronted with a situation where market participants have to work around overly prescriptive market institutions and requirements which have become an impediment to the efficient operation of the marketplace and which have harmed consumers. The existing market has not lowered prices to consumers this summer nor stimulated needed investment in new generation and transmission facilities.

The specific reforms we are proposing in this order are limited to fixing the fundamental problems which have been identified. As we move forward, we will need input from California and other Western State policymakers to help shape and further develop this new market design. But such input should recognize the regional, interstate character of the western marketplace. We expect the new non-stakeholder boards which we are ordering below to consider further refinements and to help guide the continued evolution of the market. But the Commission must take action at this juncture under Section 206 of the Federal Power Act to remedy the problems that have been found to exist in the California market structure. This action must be taken to ensure that the high and volatile prices experienced this past summer do not recur to the detriment of consumers in California and in the West generally. In this order, we focus on proposing changes to certain rules and policies of the PX and the ISO that we believe contributed to the high prices which California experienced last summer.<sup>39</sup>

#### A. Overview

One of the primary Congressional goals in enacting Part II of the Federal Power Act was to protect electric ratepayers from exercises of market power. Ratepayer interests generally centered on ensuring that rates were not excessive or unduly discriminatory. The need to ensure an adequate supply of generation usually was met through requirements imposed by states on franchise utilities to build or buy adequate power resources to meet demand consistently. Today, however, in states such as California, the adequacy of local power resources depends, not just on state requirements, but also on whether market prices are sufficient to elicit adequate supplies, through construction or otherwise. In other words, when supply is driven by market price instead of regulatory requirements, ratepayer interests may no longer depend solely on whether current prices are deemed too high, but also on whether prices are too low to elicit new supplies over time.

As indicated by the Staff Report and by reports prepared by California State agencies and others, this summer's wholesale markets exhibited certain market fundamentals that would be expected to cause prices to rise. Input

[61,359]

costs increased as the cost of fuel, emission credits and O&M expenses increased.<sup>40</sup> Sustained demand increased, requiring increased reliance on generating resources that would have been more expensive to operate even if input prices had not increased.<sup>41</sup> Conditions in the Northwest decreased amounts of hydropower supply usually available to the market which, combined with a failure to bring new generation into service over the last decade, resulted in a true scarcity of generation.<sup>42</sup> In circumstances like this, prices are expected to rise--and indeed they must rise to induce the investment in new capacity that is needed to serve customers adequately.

The issue raised in this proceeding is whether dysfunctional market rules or the exercise of market power allows prices to rise above just and reasonable levels. We conclude that certain market rules do interfere with the functioning of the market and, taken together, may permit sellers to exercise market power. Accordingly, these market rules must be revised. Many of the market dysfunctions in California and the exposure of California consumers to high prices can be traced directly to an over reliance on spot markets. Industries that are either capital intensive or that have a lack of demand response do not rely solely on spot markets where volatility is to be expected. Because the price risks inherent in spot markets are too great for both suppliers and consumers, these market sectors will prefer to manage their risk profiles through forward contracts. However, in California, certain market rules imposed by AB 1890 and its

implementation by the California Commission (*e.g.*, mandatory buy-sell through the PX) prevented the IOUs from engaging in forward contracts to any significant degree. And other retail suppliers who would have been free to implement appropriate risk management strategies could not be induced to participate in California's market because the low retail rate, frozen at 10 percent below historical levels, thwarted competitive opportunities for new participants to enter the market.<sup>43</sup> Even so, until the market was stressed this summer by extreme events, pricing volatility was isolated and short-lived and wholesale prices were so low that stranded costs were paid off more quickly than expected. The significant failings of this market design became apparent only as peak demand outstripped supply.

An essential remedy is the elimination of rules that prevent market participants from managing their risks. Moving significant amounts of wholesale transactions into forward markets will: (1) reduce reliance on spot markets, thereby directly reducing both the likelihood and the adverse economic consequences of pricing volatility;<sup>44</sup> (2) eliminate the adverse reliability impacts that the ISO faces each day as its obligation to operate a real-time balance market has become transformed into operating the major commodity exchange at the last minute; (3) increase the likelihood of new generation entry because the uncertain revenue stream from spot markets will not attract the necessary capital investments; and (4) limit the ability of sellers to exercise market power in spot markets. To address this critical problem and ensure that market participants have access to forward markets, this order proposes certain remedies intended to facilitate forward contracting.

A second critical issue we address is the ability of the ISO and PX to operate and implement wholesale markets and the ability of the ISO to operate a transmission system reliably and efficiently under the governance of its stakeholder board of directors. The functioning of wholesale markets and the reliability and efficiency of the interstate transmission grid cannot be compromised by a decision-making process that is overly complex, mired in controversy, or prone to excessive influence by special interest groups. Boards, whether comprised of stakeholders or non-stakeholders, must be able

**[61,360]**

to respond decisively to conditions necessary to maintain system integrity and operation. Most importantly, because the markets operated by the PX and the ISO are interstate markets and the transmission system operated by the ISO is part of an interstate transmission grid, the ISO's decision-making process must be responsive to the operations and the welfare of the regional marketplace, and not be restricted to the concerns of one geographic location or one segment of the market. Based on past performance, the ISO and PX boards no longer meet these standards. For these reasons, we propose to disband the stakeholder boards and direct the establishment of independent boards.

We propose several other immediate market reforms. We also identify certain other longer-term measures which need to be addressed.

Finally, because the changes we are requiring here will take time to implement and the addition of new supply is not imminent, we propose price mitigation measures through December 31, 2002. As noted earlier, a number of the changes that are required to ensure proper market functioning are within the control of state agencies. We have identified those critical issues here as well. It is imperative that these matters also be addressed during the period when price mitigation is in effect.

## *B. Proposed Immediate Measures*

### *1. Requirement to Sell into and Buy from the PX*

The California Commission Restructuring Decision required that the three IOUs sell all of their generation into and purchase all of the energy requirement for their retail load from the PX.<sup>45</sup> In so doing, the California Commission established a mechanism to ensure that the IOUs could not withhold generation from the market prior to the completion of divestiture and to value in a systematic way the above market generation assets which the IOUs had not divested. Sales at frozen retail rates in conjunction with

purchases at lower market prices created a revenue surplus from which to write off stranded costs and to transition to a regime of fully competitive prices. The requirement, in fact, was to end on the earlier of March 31, 2002, or the date when the IOUs had written off all of their stranded costs.<sup>46</sup>

During the first three years of operation, a confluence of favorable temperatures and hydro conditions resulted in such low spot market prices that the IOUs were able to write off substantial amounts of stranded costs. Because of these conditions and the valuation of their divested generation assets, the IOUs have either written off or valued virtually all of their stranded costs. However, this past summer's experience and the Staff Report make clear that these favorable market conditions have evaporated. A robust economy with little investment in capacity additions, high temperatures throughout the West and little supply response have now resulted in power costs above the frozen retail, rate levels.<sup>47</sup> The IOUs' reliance on the PX, and, in particular, the California Commission's requirement that they bid the majority (upwards of 80 percent) of their load into the PX's day-ahead and hour-ahead spot markets<sup>48</sup> created substantial short-term cost exposure and price spikes of such a magnitude that market confidence became virtually nonexistent. The details of the Staff Report paint a bleak picture of an over reliance on a spot market in a circumstance of inadequate supply. Moreover, because the IOUs have now divested substantially all of their thermal generation they are substantial purchasers of energy.<sup>49</sup> Therefore, forced sales into the PX by the IOUs to prevent withholding are no longer necessary.

As a result, we conclude that the requirement for the IOUs to sell all of their generation into and buy all of their requirements from the PX, whether in its spot or forward markets, is a significant factor contributing to rates that are unjust and unreasonable,<sup>50</sup> and we propose to declare it null and void effective 60 days from the date of this order. Under this proposal, the IOUs may elect to be their own Scheduling Coordinator rather than maintaining the current structure where the PX is the Scheduling Coordinator for the three IOUs. Without this buy/sell restriction on wholesale trade, the IOUs are free to pursue a portfolio of long- and short-term resources and access whatever wholesale markets are suited to meeting the

**[61,361]**

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.<sup>51</sup> As an independent exchange, the PX will be free to design and offer the services needed by market participants.

While we are proposing to remove an encumbrance on wholesale trades, we note that, currently, the California Commission restricts the IOUs' ability to procure forward products. These restrictions prohibit the IOUs from creating mutually beneficial long-term financial contracts with generators and marketers, and these prohibitions can result in an increase in overall prices, and the volatility of prices, to consumers.

## *2. Underscheduling of Load and Resources*

Reliable and orderly system operations require that load and resource schedules be substantially finalized on a day-ahead or day-of basis<sup>52</sup> subject to only minor adjustments to reflect more accurate information of actual system conditions as real time approaches. As a result, the ISO operates a real-time energy imbalance market to supply unanticipated changes in load and resources. This balancing market was designed to accommodate approximately 5 percent of the total anticipated load.

The record indicates that there is a chronic pattern of underscheduling<sup>53</sup> load and generation in the PX's Day-Ahead and Day-of market.<sup>54</sup> As a result, large amounts of load are not being scheduled with the ISO and the ISO is often in the position of procuring a substantial amount of energy to meet these needs in real time. In some hours the ISO has been faced with acquiring upwards of 6,000 MW of system energy needs, in real time. The ISO has reported that underscheduling was 50 percent higher this summer than the previous two summers. The cost of out-of-market purchases needed to balance load at the last minute rose to \$100 million this summer compared to about \$1 million last summer. Underscheduling has caused the ISO's operating personnel to call upon energy from capacity that had been procured for Operating

Reserves. As a result, this reserve capacity has been diverted from its intended purpose--protecting against the loss of a component of the system. In addition, the underscheduling resulted in 39 stage-one and stage-two emergencies between June and August 2000, and 13,500 MWhs of load was curtailed.<sup>55</sup> The combination of these problems places even more pressure on system operators.

As a practical matter, the ISO is often not simply providing the real-time services needed to operate a transmission system and balance the market, but is actually forced to operate an energy market and to become a market participant in order to make last minute purchases as a supplier of last resort. The PX Day-Ahead and Day-of Markets were designed as spot market exchanges; the ISO's real time market was not intended to provide this function. Underscheduling puts system reliability at risk and creates a stronger sellers' market and higher prices as real time approaches. In an attempt to address this problem, we directed the ISO in the August 23 Order to use a more forward approach in procuring these energy needs.<sup>56</sup>

As discussed above, the elimination of the buy/sell requirement in the PX will allow for greater discretion for the IOUs to self supply or to procure resources in bilateral or other markets for their energy requirements as well as necessary ancillary services. We believe that the existing underscheduling problem is addressed in part by this revision to the market. We propose to temporarily correct the current situation by limiting the ISO to only the functions needed to reliably operate the transmission system, *i.e.*, provide a balancing service rather than running an energy market. To address this reliability problem and to ensure that loads do not rely excessively on the ISO as the provider of last resort, we propose to establish a penalty charge for deviations in excess of five (5) percent of an entity's hourly load requirements.<sup>57</sup> Loads in excess of this deviation band that are not scheduled in the Day-Ahead or Day-of Markets will be assessed a penalty charge of two times the ISO's real time energy cost for any purchase of balancing energy during the hour. The penalty will not exceed \$100/MWh (*i.e.*, the actual imbalance cost

**[61,362]**

plus \$100), which approximates the current charge assessed to underscheduled load for replacement reserves. As to the penalty, we have long set disincentive rates for emergency service at twice the standard rate, and we will apply that policy here.<sup>58</sup> As a further incentive to encourage accurate scheduling in the Day-Ahead or Day-of Markets, we propose to direct the ISO to disburse at the end of the billing period all penalty revenues (revenues above costs) *pro rata* to the loads that scheduled accurately and that did not exceed the 5 percent deviation band for that hour. In addition, later in this order we propose to remove one of the financial incentives for sellers to favor the real-time market by providing that suppliers in the real-time market receive either a capacity payment for replacement reserves or energy payments, but not both. We also describe later in this order auction modifications that should eliminate the need for the ISO to go out of market to procure energy needed for the balancing market. As a result, loads when properly scheduled will be better able to access required supply. We believe that this more orderly process for system operations in conjunction with the ISO's use of forward contracts will better enable the ISO to reliably operate the transmission system.

Underscheduling is a symptom of many of the other market flaws.<sup>59</sup> Because our order addresses many of these problems we expect the underscheduling problem to subside. The ISO should consider other market design changes that would address underscheduling.

### *3. Governance of the PX and ISO*

The Commission conditionally authorized the establishment of the ISO and PX in November 1996.<sup>60</sup> In that order, the Commission noted the accelerated schedule for commencement of operations and committed to dedicate the necessary resources to accomplish that schedule. The Commission also expressed its intent to give great weight to the views expressed in the California Restructuring Legislation. The Commission's deference is most apparent with respect to the governance of the ISO and PX. The parties had proposed that the ISO and PX would be governed by boards composed of individuals residing in California who were chosen to represent various stakeholder classes (*i.e.*, transmission owners, municipal entities, sellers, end-users, *etc.*), with each class having a specified number of voting representatives. The Governing Boards

would be responsible for broad operating criteria, rather than daily decisions and functions, and members were to vote individually, not as a class. As initially proposed, the Oversight Board was intended to perform two primary functions: (1) establish nominating/qualification procedures for the ISO and PX Governing Boards, determine the composition of Board representation, and select Board members both initially (Start-Up Function) and in the future; and (2) serve as a permanent appeal board for reviewing ISO Governing Board decisions.

The Commission accepted the proposed Governing Boards (as modified by the Restructuring Legislation) except for the proposed California residency requirement, finding them to be consistent with the ISO Principles of [Order No. 888](#).<sup>61</sup> The Commission relied on the fact that no one voting class would be able to block or veto actions and that no two classes together would be able to form a sufficient majority to make decisions, and on the codes of conduct that would govern board members' behavior. In an effort to assist in the advancement of the California restructuring process, the Commission granted limited authorization to the Oversight Board's Start-Up Function, subject to all determinations made by the Oversight Board being filed with the Commission for final review.<sup>62</sup> The Commission, however, was troubled by the role for the Oversight Board in the governance and operation of the ISO and PX and the appellate review of ISO Board decisions, because these matters were-and remain-within our exclusive jurisdiction.<sup>63</sup> Consequently, the Commission stated that the continuing functions of the Oversight Board established by the Restructuring Legislation would conflict with our statutory duties under

**[61,363]**

the Federal Power Act and could not remain a part of the proposal.<sup>64</sup>

The Commission recognized, however, that states have a legitimate oversight role with respect to traditional retail matters such as: protecting the welfare of the state's retail consumers and citizens; protecting the reliability of electric service to California retail consumers; ensuring the adequacy of the generating and transmission resources necessary to achieve designated planning and operating reserve criteria to ensure adequate service to end-use consumers; monitoring whether the California retail electricity market is a well-functioning market and delivers the public benefits for which it was developed; and ensuring that the ISO and PX keep retail consumers adequately informed of matters affecting retail electric consumers. The Commission further stated that this role would not conflict with its jurisdiction and would address state-jurisdictional matters.<sup>65</sup>

The Oversight Board subsequently filed a petition for declaratory order requesting that the Commission declare that a bill pending in the California Senate (SB 96), modifying the Board's duties under the Restructuring Legislation, if enacted, would resolve the Commission's concerns about its role.<sup>66</sup> Rather than giving the Oversight Board confirmation power over all members of the ISO and PX Boards, SB 96 afforded the Oversight Board confirmation rights over a limited number of members representing primarily end-users, and addressed the residency requirement. In addition, the structural composition of the Governing Boards was to be modified as soon as another state were to participate in the ISO and PX. SB 96 provided that California could change the ISO and PX Governing Boards into non-stakeholder boards, subject to filing revised Bylaws with the Commission. SB 96 also limited the function of the Oversight Board as an appeal board to ISO decisions regarding eight distinctly state-retail matters.<sup>67</sup> In the *Oversight Board* decision, we accepted, as consistent with the FPA, the Oversight Board's limited interim appointment function and limited appellate review rights set forth in SB 96.

Events over the past two years increasingly have made clear that the ISO Governing Board has such difficulty reaching decisions on the complex and divisive issues confronting it that it has become ineffective. The Staff Report comments on this deficiency.<sup>68</sup> For example, from this Commission's perspective, ancillary services are a critical part of a competitive market. However, the ISO's redesign of its Ancillary Services markets, which was intended to be a global, comprehensive effort to be implemented within perhaps nine to twelve months, has been approved and implemented in piecemeal fashion over a very long term. Similarly, the ISO's reform of its congestion management program has been embroiled in dissension and postponed beyond a reasonable length of time.<sup>69</sup> Most recently, the ISO's efforts to address

this summer's price abnormalities could not be resolved by its Governing Board. The ISO's October 20, 2000 submission in this proceeding was not submitted to the Governing Board for its consideration. A news report quotes the ISO's President and CEO explaining that no consensus regarding market mitigation proposals could be developed " 'since everyone had a different concern or a different idea' for how to change the market." <sup>70</sup>

In addition, over the course of this summer, it has become apparent that the Governing Boards are not functioning as they were intended to. Members of the ISO Board, in particular, have come under undue pressure from various sources, notably regarding votes to change the purchase price cap level. One member even felt compelled to resign, and her parting words encouraged her colleagues "to find the determination to stand for the principle that the ISO must be independent of manipulation by any market participant." <sup>71</sup> Several other members also noted pressure "from people that are very powerful." <sup>72</sup> The Staff Report found indications that the Boards have been susceptible to influence by market participants, particularly by the interest that they

**[61,364]**

represent. <sup>73</sup> Even California authorities have concerns about the Boards' independence. A joint Report to the Governor authored by the California Commission and the Oversight Board notes that the ISO and PX "are governed by boards whose members can have serious conflicts of interest." <sup>74</sup>

On this record, we have no choice but to conclude that the existing California ISO stakeholder board is ineffective and must be modified. The ISO is an institution that is central to the functioning of wholesale power markets in the West and, unless it is able to resolve matters in a timely manner and is independent from market participants, we cannot be assured that rates, terms or conditions of its jurisdictional services will be just, reasonable and not unduly discriminatory or preferential. The transmission assets that the ISO operates are a critical part of the interstate transmission grid located in the Western Interconnection which provide essential support to the electric market. Any failings by the ISO in its obligation to ensure reliable operation of the transmission grid would have grave consequences for the residents and business in the Western states. Operation of this interstate transmission grid must be controlled by an expert board which is free from the influence of any market participant or market segment. <sup>75</sup>

We have similar concerns about the independence and effectiveness of the PX Board. The PX was created to accommodate California's retail access program. However, as discussed in detail below, effective 60 days from the date of this order, we propose to lift the requirement that the IOUs sell into and buy from the PX. Consequently, there is no longer any need for a stakeholder body to govern the PX; it may be operated as any other power exchange by independent directors.

While we are proposing to require the removal of the current boards, we recognize that the management of both the ISO and PX have performed admirably working under extreme circumstances and within the system dictated to them both during the initial start-up phase and more recently through the extreme conditions of the summer. We also recognize their tireless work with the stakeholder boards, a situation that was also dictated to them. In order to ensure a successful transition, it is vital that continuity of management be maintained.

We propose in this order that the current stakeholder boards be replaced with non-stakeholder boards effective 90 days after the date of this order. Under this proposal, in order to accommodate this schedule we will require that each new independent non-stakeholder board consist of seven voting members with the President (or CEO) as a voting member. The six other voting members will be selected by the current boards of the ISO and the PX, from a separate slate of candidates for each entity prepared by an independent consultant. The consultants are to be selected by the CEOs of the ISO and PX. The Boards should include members with experience in corporate leadership (at the director or board level) or professional expertise in either finance, accounting, engineering or utility law and regulation. The PX board should include members with expertise in areas of commercial markets and trading. The ISO board should include members with experience in the operation and planning of transmission systems. To allow

sufficient time for this transition to occur, we propose to require the current ISO and PX Governing Boards to vote in new independent, non-stakeholder board members selected from the consultant's slate of candidates and disband the existing stakeholder boards within 90 days from the date of this order. We emphasize that the sole responsibility of the existing boards in the selection process is to pick from the slate of qualified candidates identified by the independent consultant.

The ISO and PX have well-established market monitoring units and independent surveillance committees that monitor their respective markets. This monitoring function focuses on trading activities and structural factors. In the October 30, 1997 Order, we accepted the ISO and PX proposal allowing market reports to be filed directly to regulatory agencies.<sup>76</sup> While these entities currently have the discretion to file their reports directly with the Commission, we propose that effective 60 days after the date of this order that all ISO and PX market reports be filed by the ISO and PX with the Commission at the same time that they are released to their respective boards.<sup>77</sup> This requirement will allow the Commission more timely information on market behavior.

#### *4. Interconnection Procedures*

While siting issues are not within this Commission's jurisdiction, we note that tariff interconnection

[61,365]

policies are. Further, we note that standard procedures to facilitate the interconnection of new generators or existing generators seeking to increase the rated capacity of their facilities are needed in California. In this regard, we find that the ISO tariff lacks any such procedures and we direct the ISO to file generation interconnection procedures no later than sixty (60) days after the Independent Board is seated. This will ensure that the Commission may facilitate the matters under its control in a timely manner.

#### *C. Longer-Term Measures*

We believe that current structure in California also requires a number of longer-term reforms. While the Commission is not dictating any particular revision we propose to direct that the following issues be addressed.

##### *1. Reserve Requirement*

Adequate reserves to ensure system reliability is closely related to establishing a price that elicits a supply response. Matters of planning reserve and reliability are ill-suited to the lag inherent in a market response to short supplies. Attracting sufficient supply to maintain proper reserve requirements may well benefit from the imposition of planning reserve requirements to be met from forward markets. Suppliers would be able to build capacity with the financial assurance of long-term contracts and would be less tempted to wait until spot prices were driven up by low reserve levels. We direct 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. Alternative Auction Mechanisms*

In times of adequate supply the single price auction disciplines prices by encouraging suppliers to bid their marginal costs so that they can be selected for dispatch and be paid the clearing price. However, in times of scarcity the single price auction can exacerbate the effect of supply shortages by allowing sellers who have small market shares to set the clearing price. Not only is the seller transformed into a price setter rather than a price taker, but the resulting price is ascribed to the entire market. We are concerned that given the current market in California, the single price auction may place little or no discipline on sellers during times of shortages by minimizing the risk of strategically bidding a small amount of supply for the purpose of raising the price of the entire market. It is for these reasons that we propose to mitigate prices by eliminating the use of a single price auction at prices above \$150. While our proposed market reforms will

mitigate some of the effects of the single price auction, we believe that further study of this issue is desirable and direct the PX and the ISO to consider, during the 24 month 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. Balanced Schedules*

We are also concerned that some of the underscheduling problems may be a result of the existence of many individual scheduling coordinators that are required to submit balanced schedules to the ISO. We therefore direct 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. Enhanced Market Mitigation*

We direct the ISO and the PX to consider less intrusive, narrowly tailored market protection mechanisms. Such mechanisms could take the form of the ex ante identification of conditions or behavior that would trigger specific market mitigation actions.

### *5. Congestion Management Redesign*

In *California Independent System Operator Corp.*, [90 FERC ¶61,006](#) (2000), the Commission found the ISO's existing congestion management structure to be flawed, and, on that basis, we directed the ISO to develop and submit to the Commission a comprehensive congestion management redesign. Moreover, we stated that such a redesign should be pursued with input from *all* stakeholder groups, as well as from the ISO's Market Surveillance Committee. The reform efforts have been the subject of extensive public review and comment which are nearing completion, and a submission is due to be filed in the near future.

More recently, in the August 23 Order, we stated that we would defer any consideration on the merit of the ISO's congestion management structure until the earlier of the ISO's filing of its reform proposal or the date which the Commission issues a supplemental order in this proceeding. While we consider the ISO's congestion management reform efforts to be crucial, we now believe that this particular aspect of the California market is not a significant source of this summer's high prices and volatility.<sup>78</sup>

We are however concerned about the delay caused by the existing ISO Board on this matter. Therefore we direct the new Independent ISO Board to file its redesign proposal no later than sixty (60) days after the Independent ISO

**[61,366]**

Board is seated with an implementation date as soon as possible. The current congestion management system is fundamentally flawed and needs to be overhauled or replaced. This market redesign is crucial for providing transmission schedules that are based on physical reality and accurate price signals for the siting of new generation. Therefore we will require that the proposal, at a minimum, include a meaningful number of zones that significantly address congestion on the system. In this regard, we also require 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). We also expect the ISO to conduct a periodic (annual) review to evaluate the accuracy of the zones for congestion management. We will take any requisite action on that proposal at the time it is filed in a separate proceeding.

### *6. Demand Response Program*

As the Staff Report observed, the difficulty with current demand response in California is that it is driven by administrative directive, not market prices. (Staff report at 5-21). We direct 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.

## *7. Importance of RTO Development and Compliance*

As discussed earlier in this order, California is physically integrated into an extensive interstate transmission grid and has therefore been part of a western electricity market for a long time. California's markets will never realize optimal performance until the impediments to efficient utilization of the regional transmission grid are eliminated and the regional interstate transmission system is designed in such a way that it supports transparent, competitive Western bulk power markets--markets that support all of the wholesale products that California requires, markets that remove impediments to efficient imports and exports, markets that eliminate rate pancaking and allow California to access more distant markets at a lower cost, markets that undertake regional transmission planning to ensure that the needs of California are considered when transmission expansions in other states are considered, and markets that allow regional market hubs like Palo Verde to develop where new generation can be located to serve multi-state markets. The Commission's RTO initiative is a response to fundamental changes in the electricity industry over the last 20 years. When fully implemented, RTOs will provide for operation and planning that will ensure consumer benefits for Californians and the citizens of other Western states. The problems being confronted in California can, in many ways, be traced to the continued balkanization of the Western grid and the absence of a true RTO with regional scope. The actions we have taken in this order are fully consistent with [Order No. 2000](#), and nothing in this order relieves the ISO, PG&E, SOCal Edison or SDG&E from their obligation to make a filing in compliance with [Order No. 2000](#) on January 17, 2001. We expect that the matters addressed in this order will move the California market toward meeting the significant objectives of [Order No. 2000](#) and that these long-term market reforms will facilitate California's transformation into a properly sized and functioning RTO.

### *D. Price Mitigation and Refunds*

The Commission has found in this proceeding that the existing market structure and market rules, in conjunction with an imbalance of supply and demand in California, have caused and, until remedied, will continue to have the potential to cause, unjust and unreasonable rates for short-term energy during certain time periods. While the Staff Report lists a number of factors that legitimately led to higher prices last summer,<sup>79</sup> it also recites market design problems that contributed to high prices and that may have provided incentives for the exercise of market power or otherwise led to higher than competitive prices.<sup>80</sup> As long as a flawed

[61,367]

market design remains in effect, the possibility for non-competitive prices will continue to exist. Accordingly, pursuant to our statutory responsibility under FPA Section 206, the Commission not only must "fix" those areas of market design that are within its jurisdiction and that are causing the potential for unjust and unreasonable rates (*i.e.*, require modifications of existing wholesale market structures and market rules that are impeding a competitive price), we must also provide measures to assure that rates remain just and reasonable until such time as the proposed longer term market remedies can be effectuated.

Below we address two components of protecting ratepayers against unjust and unreasonable rates. First, we address price mitigation measures that will remain in effect for 24 months, which is the time necessary to effectuate all the longer term market structure and market rule changes being required. Second, we address the refund liability of public utility wholesale sellers in the ISO and PX markets who may have the ability to charge unjust and unreasonable rates during certain time periods.

#### *1. Price Mitigation Measures*

Between 1996 and 1999 California added about 700 MW of generation while its peak load grew by some 5,500 MW fueled by an annual population growth of 600,000 people and a robust economy. As a result, California's recent peak load and its available installed capacity (*i.e.*, in-state capacity not down for maintenance) are effectively equal at about 45,000 MW; *i.e.*, there is often barely enough supply to meet

demand. This leaves California vulnerable to price spikes caused by even small suppliers who, under tight supply conditions, can affect the PX and ISO market clearing prices. These conditions can allow the exercise of market power.<sup>81</sup> These higher spot market prices in turn affect the prices in forward markets. While California has 8,000 MW of import capability, WSCC reserves during peak hours in May and June dropped to about 5 percent, compared to forecasted planning reserves of 17-20 percent issued earlier this year, and therefore less energy was available for purchase from out of state.<sup>82</sup> In addition, as virtually all reports on this market conclude, there is at present little demand responsiveness to price. Accordingly, we propose price mitigation in order to allow sufficient time for the implementation of the remedial measures we are proposing to order herein as well as the development of additional supply and demand response measures. As discussed, *infra*, the price mitigation measures will be in effect for a period of 24 months.

First, we have proposed to free the IOUs of the trade restriction of selling all of their generation into and buying all of their supply from the PX. This permits the IOUs to avail themselves of the bilateral market and forward markets and the ability to self-supply. In so doing, the IOUs now have the ability to mitigate their own prices, and minimize their exposure in the spot market. Second, requiring California market participants to preschedule all resources and loads with the ISO coupled with a penalty on all energy transactions of greater than 5 percent of the prescheduled amount should greatly reduce the amount of supply traded in the real-time market and, thus, will shelter Californians from the huge exposure to spot prices experienced this summer.

We propose to implement a temporary modification to the single price auctions of the PX and the ISO. A significant factor causing high prices in California was the fact that every MW in the market is priced at the market clearing price. We propose that, effective 60 days from the date of this order, for all short-term markets operated by the PX and the ISO (including the Replacement Reserve Market), the single price auctions be used for all sale offers at or below \$150.<sup>83</sup> This auction modification imposes no limits on a seller's bid and only limits which bids can set the clearing price. The single market clearing price will be used for the amount of load which clears at or below this amount in the auctions. To the extent an auction does not clear at or below the \$150 bid level, suppliers who choose to bid

**[61,368]**

above \$150 will be paid their as-bid price.<sup>84</sup> These prices will be averaged and billed to all the load which was supplied in the auction.<sup>85</sup> Allowing generators to receive their as-bid price should permit generators whose costs exceed \$150 to participate in the market and continue to attract new supply by reflecting in prices the true cost of scarcity.<sup>86</sup> This pricing method takes care to mitigate prices by reflecting a price to sellers at the margin which signals the supply and demand conditions rather than reverting to a traditional cost of service basis (*i.e.*, a regulated price which reflects the cost of all assets without any regard to market conditions). This is crucial in order to induce new supply. Bids using this modified single price auction will continue to be disciplined by low and moderate cost suppliers bidding their marginal costs at times other than shortages to ensure that they are chosen for dispatch and can receive the clearing price. At times of shortage, we will discipline prices through reporting requirements and monitoring as discussed below.

We propose to require the PX and the ISO to report confidentially to the Commission on a monthly basis all bids (both for public utilities and non-public utilities) in excess of \$150, including the name of the seller, the price and amount of MWs covered by the offer, the hour(s) covered by the offer, the bid sufficiency in the market (*i.e.*, the total amount bid compared to the amount needed), and the load at the time of the offer. The ISO also must report unit availability data for all Participating Generators. The first report must be filed no later than February 15, 2001 for the period January 1, 2001 through January 31, 2001, and subsequent reports must be filed no later than 15 days after the end of each month. This will permit the Commission to monitor the effectiveness of the \$150 breakpoint and any attempted exercise of market power by the market participants.

In addition, to adequately monitor the competitiveness of markets during the 24-month period and ensure just and reasonable rates during the time it takes to effectuate the longer term structural and market rule remedies, we propose to condition the public utility 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 exceeds \$150 effective sixty (60) days after this order. We propose to require all transactions for the prior week to be filed on a confidential basis to the Commission's Division of Energy Markets in a single report submitted on the Wednesday following the end of the transaction week (ending midnight Sunday). These market data 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. The filing may also identify legitimate opportunity costs that are known and verifiable that the seller considered in developing its bid, *i.e.*, prior to the transaction. These data will be used to monitor prices on a more current basis, 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.

We recognize that some parties have offered alternative price mitigation measures and our decision here is informed by those alternative proposals. We believe that a comparison of the major attributes of some alternatives that have been proffered shows that the option we have selected is appropriate. For example, some parties propose that bids into the single price auction be capped at a specific level. Recognizing that the single price auction magnifies the impact when the maximum bid does not reflect the competitive outcome, by paying that same

**[61,369]**

price to all sellers in the market, proponents of these measures seek lower and lower ceilings to reduce the economic consequences. However, ceilings set too low can also have severe short-term and long-term consequences on the market. Recognizing these concerns, some alternative proposals would include load-differentiated price caps that are indexed to estimated load and changes in input costs. These proposals, however, introduce significant complexity into a market that is already in dire need of simplification. We believe that our approach addresses the concerns that underlie these alternatives.

We select \$150 as the level above which we will require reporting and increased monitoring because this level is indicative of high demand. Our review of the bids that cleared in the PX's Day Ahead market in August tells us that bids exceeded \$150 in about 45% of the hours in the month. All these bids were in the peak hours of about 10 AM to 10 PM. The PX Deficiency Report also shows that during the hours of 11 PM to 6 AM prices exceeded \$100 nearly 75 times or about 10% of the hours of the month and about 30% of the off-peak hours. We intend to rely on the single price auction to discipline prices in off-peak hours when supply should be adequate.

We must also take care not to place our breakpoint so high as to provide little or no mitigation other than in periods of extreme weather conditions such as California faced in August. Our review of the bids which cleared in the PX Day Ahead market for September, when the heat wave subsided, indicates the use of a higher break point of \$200 would have reduced price mitigation to 9% of the hours.

Our selection of the \$150 breakpoint is also informed by the running costs of the gas-fired generation which is and which we expect to be on the margin in California. Selecting a breakpoint which is below or barely exceeds the running costs of new entrants is not in the interest of consumers. In this critical regard, we have also selected \$150 because the Staff Report indicates that the running costs alone of gas-fired generation often exceeded \$100 during the Summer, and our review indicates that they have not substantially abated.

We have also decided not to propose indexing the \$150 to gas and NOx cost changes in the future. We believe that market entry is promoted by simplicity, transparency and stability in pricing rules and, therefore, intend to avoid the uncertainty inherent in varying this figure. To the extent these costs abate to some degree, we expect to see a favorable supply response. There is little sense in increasing our reporting requirements at the very time the market is self-correcting. Conversely, the \$150 breakpoint is some \$60 above current gas and NOx costs for a combined-cycle plant. Accordingly suppliers should be able to absorb some rise in gas and NOx costs and still have the option of bidding at the \$150 level which does not trigger reporting and monitoring.

We also select \$150 as a reasonable benchmark for the cost consequences of a tight supply. Existing gas fired units<sup>87</sup> were operated at unprecedented levels, driving up the price of NOx emission allowances from around \$6/lb. to over \$40/lb. at the end of August.<sup>88</sup> In addition, gas prices have risen from \$2/MMBtu in the spring to about \$5/MMBtu now.<sup>89</sup> The \$150 figure will accommodate these marginal running costs for a combined cycle generating unit and permits some contribution to fixed costs.<sup>90</sup> As a result, existing suppliers and new entrants whose marginal costs allow them to bid within these parameters will not be burdened by reporting requirements. This will minimize our intrusion in these markets and should attract new suppliers. Those suppliers who cannot accommodate their financial needs at or below this breakpoint will be paid the as-bid price, but will be required to report so that we can monitor their bids.

Prices based on traditional cost of service are incompatible with fostering a competitive market because the cost of the assets will not reflect supply or demand conditions. In choosing our price mitigation approach, it is our intent to guide these markets to self-correct, not to reintroduce command and control price regulation. Monitoring bids above the \$150 breakpoint will allow the market to respond over the next 24 months by ensuring that prices reflect the cost of scarcity while allowing us to mitigate potential market power.

## **[61,370]**

Above we established monthly reporting requirements for the ISO and PX and weekly reporting requirements for certain sellers effective upon issuance of our final order. We are also concerned about the market performance between the refund effective date and when our final order becomes effective. Therefore, for this period we propose to establish the same reporting requirement on the ISO and PX with respect to bids that exceed \$150. The ISO and PX reports will be due no later than January 30, 2001.

We expect that standardized electronic filing of these reports would facilitate processing of this information and we will finalize our guidance on this point in our final order.

### *2. Refund Liability of Public Utility Sellers in the ISO and PX Markets*

#### *A. Refund Liability for the Period October 2, 2000 Through December 31, 2002*

The Commission has specific authority in Section 206 to order refunds, if it deems them appropriate, from the refund effective date to a period 15 months following the refund effective date. In our August 23 Order, we noted that refunds were discretionary and that refunds may be an inferior remedy from a market perspective and not the fundamental solution to any problems occurring in California markets. We further stated that while we must protect ratepayers, we do not intend to undermine the financial stability of public utility sellers and that any decision on whether to impose refund obligations would be based on our findings regarding just and reasonable rates and a balancing of consumer and investor interests.

In our August 23 Order, pursuant to Section 206 of the FPA, the Commission established a refund effective date 60 days from the date of our order instituting an investigation on our own motion into the practices of the ISO and PX. On September 22, 2000, SoCal Edison and PG&E filed for rehearing of this date, seeking a refund effective date beginning 60 days after the filing of SDG&E's complaint in [Docket No. EL00-95-000](#). The Commission will grant SDG&E's request to establish the earliest refund effective date permitted under Section 206, which will be October 2, 2000.

We are not now proposing to order any refunds. However, having now reviewed the price volatility that has occurred in California and the flaws in the market design that can lead to unjust and unreasonable rates during certain time periods, we propose that sellers remain subject to potential refund liability during the period it takes to effectuate the longer term remedies proposed herein. We must be vigilant that market manipulation or other anticompetitive behavior does not occur and that the combination of market rules and supply shortage does not otherwise produce unjust and unreasonable rates while the flawed market design remains in effect. Thus, we conclude that not only is the market monitoring through increased reporting,

discussed previously, appropriate, but circumscribed refund liability also is appropriate. Therefore, if the Commission finds that the wholesale markets in California are unable to produce competitive, just and reasonable prices, or that market power or other individual seller conduct is exercised to produce an unjust and unreasonable rate, we may require refunds for sales made during the refund effective period. However, should we find it necessary to order refunds, we will limit refund liability to no lower than the seller's marginal costs or legitimate and verifiable opportunity costs. This will achieve an appropriate balance between ratepayer protection and the seller's ability to have an opportunity to recover its costs.

Finally, because the refund protection under Section 206 will end 15 months following the October 2, 2000 refund effective date, and because we cannot be assured that rates will remain just and reasonable until longer term remedies are effectuated, we propose to condition the market-based rate authorizations of public utility sellers in the ISO and PX markets on continuing a refund obligation until such time as the longer term remedies are in place (as discussed herein, a period ending December 31, 2002). Such potential refund liability, as discussed above, would be no lower than the seller's marginal costs or legitimate and verifiable opportunity costs.

#### *B. Refund Liability for Period Prior to October 2, 2000*

The Commission has proposed in this order to remedy the structural inadequacies of the California bulk power market as quickly and as comprehensively as possible. Nevertheless, the most persistent request made of the Commission by California officials is to return the ratepayers in the SDG&E service territory to the financial circumstances they would have experienced this past summer but for the series of problems in California's retail, and by implication its wholesale, electricity markets. Such equitable relief would take the form of a retroactive refund of amounts in excess of just and reasonable wholesale rates. During the September 11, 2000 Congressional hearing in San Diego, members of Congress stressed the need for relief for the citizens of that city. Consequently, the Chairman of the Commission, at that hearing, agreed to have staff thoroughly review the state of federal law as it pertains to ordering retroactive refunds of wholesale rates.

The Staff Report, our own San Diego hearing, and all the facts collected about this summer's

**[61,371]**

market dysfunctions attest to the unanticipated hardship imposed on California ratepayers. The rate shocks were severe and unanticipated by consumers. We understand the distress of San Diegans, the concerns of their public representatives, and the adverse impacts on certain sectors of the local economy, but these factors cannot alter the limitations on the Commission's authority to change rates that were previously approved, even if subsequently found to be unjust and unreasonable. The FPA and the weight of court precedent strongly suggest that retroactive refunds are impermissible in these circumstances. *See* Appendix E. The Congress has refrained during the 65-year history of the FPA from granting such authority in part because of the uncertainty it would create in regulated wholesale markets for power. The FPA itself was created, not to redress traumatic and inequitable circumstances like this, but to provide rate certainty in a relatively static monopoly environment. It may be argued that the dynamic power markets of today may warrant changes in the Commission's refund authority, at least for extreme circumstances, but that does not help the Commission today as it considers rate relief to the citizens of San Diego for the summer just past.

91

The economic distress of high rates is an immediate concern. However, the Commission believes that real rate relief for California electricity consumers will be fully realized in the State when sufficient new generation and transmission resources can be attracted and built and better demand-side responses can be prompted. Only competitive markets will do these things. We believe it would be a mistake to revert to the kind of rate regulation that contributed to the decline in investment that clouds California's energy future today. On the other hand, the Commission recognizes that market-based rates will only achieve just and reasonable rates where competition works effectively and market rules are effective and fair. The Commission can, and must, focus its efforts in this area.

E. Docket Nos. ER00-3461-000 and ER00-3673-000

Consistent with the above discussion, we will reject the price cap proposed by the PX and the purchase cap amendment filed by the ISO. While the ISO purchase price cap has served to mitigate price volatility in both the ISO and PX markets, nonetheless it has served to disrupt the market by encouraging sellers to stay out of the PX's auction and wait for the ISO to make the needed purchases on an out-of-market basis at the last minute. As we noted in the August 23 Order,<sup>92</sup> all the PX and ISO markets are interrelated such that any significant modification to one market will affect the other markets. Our proposed modification to the single price auctions is intended to establish uniform pricing and remove incentives for the load and resources to participate in one market over another. For this reason we will not allow, at this time, either the PX or ISO to implement changes that will disrupt this uniformity or to introduce new incentives in the markets. Moreover, we are attempting to provide a period of stability in the market in order to encourage supply to enter the market. Therefore we will reject the PX and ISO proposals. In the interest of maintaining stability in the markets during the transition prior to imposing the instant market reforms, we hereby order that the current \$250 ISO purchase cap remain in place at that level until sixty (60) days after the date of this order.<sup>93</sup>

We will sunset all price mitigation on December 31, 2002. We conclude that 24 months is sufficient to restore order to these markets. We discuss below several critical market corrections which must be addressed during the 24-month window and we discuss further the removal of the auction reform after this 24-month window.

F. *Actions Others Should Take*

In well functioning markets which exhibit ease of supply entry and demand response to price, consumers react to scarcity by either demanding more supply or reducing demand. The current situation in California leaves us faced with little supply entry and essentially no demand response. The Staff Report documents that this phenomenon contributed to high prices in a sellers' market which were not sufficiently disciplined by supply and demand responses which consumers usually make in setting a scarcity price. It is for this very reason that we have adopted a price mitigation which reflects a measure of scarcity costs without allowing sellers to systematically set the clearing price for the entire market.

In setting a 24-month window to remedy market problems, we are mindful of the fact that the structural defects in the California

[61,372]

market have been created over many years in an environment which relied on regulatory rather than market responses to consumer needs. We have intervened not to shelter Californians from the consequences of their choices, but to allow a two-year period of transition during which the California Commission and other interested parties can make an informed decision of whether these are the decisions they wish to make for the future in a considered and deliberative environment without the distraction of destabilizing price spikes and an increase in overall power costs. At the end of our 24-month window, we intend to lift the \$150 auction modification. At that time, prices will be the product of the informed choices Californians have made on supply and demand and will reflect the true scarcity cost which they place on electric generation.

1. *Offering a Full Menu of Forward Products*

As noted, many of the remedies we are proposing are intended to move loads into forward markets. Success in this objective is, of course, contingent on the availability of supply in forward markets. While we understand that the pricing offered for each type of forward product may vary to reflect the terms offered (e.g., length of contract, risk apportionment, peak vs off-peak), we fully expect that California suppliers will welcome the opportunity to offer a full range of forward products to meet the needs of their

customers. To the extent that a full range of forward products (*e.g.*, short-term, intermediate term and long-term products) do not become available in California, we expect that load-serving entities will bring that to our attention. Whether the Commission should require sellers to provide a certain percentage of product offerings in the forward market is one issue that the Commission will consider in this proceeding.

## *2. Additions of Generation and Transmission Capacity*

There is little doubt that the most crucial task ahead is to ensure that a robust supply enters this market, both now and in response to any future price signals. The Staff Report underscores inadequate siting of generation and transmission as a key structural defect in California. We have made every effort in this order to eliminate market design flaws in a manner that promotes efficient markets in order to reduce consumers prices to the extent possible given the current inadequate supply. However, prompt access to new generation is needed to ensure full consumer benefits are realized. For that reason, we have also carefully crafted our proposed remedies so as to avoid circumstances that may deter new entry, *e.g.*, prices set too low can prevent new entry, indecisiveness about the specifics of market reforms and price mitigation can deter new entry, and market rules that place restrictions on the operation of efficient markets can deter new entry.<sup>94</sup>

However, the Commission's authority does not extend to siting, and without appropriate siting support, consumers in California will continue to pay higher prices due to inadequate generation supply. The 24-month price mitigation we have ordered herein will afford the state and local agencies a window to streamline, facilitate and accelerate the siting of needed generation and transmission, including the specific projects identified in the Staff Report as furthest along in the planning and siting process and, therefore, most likely to be completed in the shortest time.<sup>95</sup>

Finally, this Commission will commit to expeditiously process any energy facility applications (hydroelectric or gas pipeline) within its jurisdiction, within the constraints of the law and the need for multi-agency coordination.

## *3. Demand Response*

Another matter that lies primarily within the control of state policymakers is the development of demand side response. Demand side is a critical element of the market. When consumers can receive price signals and have the ability to respond to those price signals by reducing demand, it reduces the overall cost of electricity in the market and reduces the electric bills of all consumers, not just those that responded with a load reduction. Also, a viable demand response program provides an alternative to resource expansion. The price mitigation period proposed in this order provides state policymakers with a 24-month window to develop demand response programs, and an important opportunity to take measures that can help reduce prices to California consumers.

## *4. Elimination of Impediments to Forward Contracting*

As noted the use of forward products to hedge against spot prices is crucial to the development of a well functioning market. We encourage the California Commission to eliminate restrictions on the IOUs availing themselves of long term products.

**[61,373]**

### *Hearing Based on Written Submissions and Oral Presentations to the Commission*

In our August 23 Order, we did not determine the type of hearing that would be needed in this proceeding. Based on the information provided in the Staff Report and the submissions in the record thus far, and the nature of the issues presented, we conclude that a trial-type hearing is not necessary to resolve the matters before us.<sup>96</sup> Further, the need for expeditious resolution of the problems inherent in California markets call for as expeditious a hearing as possible, consistent with due process and the development of an adequate

record. Accordingly, the Commission will provide the parties an opportunity to file comments, containing all arguments and all supporting evidence that they wish to present. All such comments must be filed by November 22, 2000, which is three weeks from the date of this order. Reply comments will not be entertained. In addition, the Commission will convene a public conference on November 9, 2000 for interested persons to discuss the proposed remedies. A transcript of this conference will be placed in the public record of this proceeding.

Based on the record developed in this proceeding, including comments and additional information placed in the record in [Docket Nos. EL00-95-000](#), [EL00-98-000](#), and [EL00-107-000](#), and the Staff Report, the Commission will issue by the end of this calendar year, a final order adopting and directing remedies to address the identified problems adversely affecting competitive power markets in California, and if necessary, ordering any further procedures to develop remedies to other identified problems.

*The Commission orders:*

(A) The parties may submit to the Commission additional arguments and evidence as outlined in the body of this order, by November 22, 2000. A party's presentation should separately state the facts and arguments advanced by the party and include any and all exhibits, affidavits, and/or prepared testimony upon which the party relies. The statement of facts must include citations to the supporting exhibits, affidavits and/or prepared testimony. All materials must be verified and subscribed as set forth in [18 C.F.R. §385.2005](#) (2000).

(B) The PX's proposed tariff revisions filed in [Docket No. ER00-3461-000](#) are hereby rejected.

(C) The ISO's proposed tariff revisions filed in [Docket No. ER00-3673-000](#) are hereby rejected.

(D) The ISO is directed to implement a \$250 purchase price cap, without disturbing the ISO's \$100 price cap for replacement reserves, for 60 days, commencing on the date of this order, as discussed in the body of this order.

Commissioners Massey and Hébert concurred with separate statements attached.

*Appendix A--Timely Intervenors in ER00-3461-000*

California Department of Water Resources

California Electricity Oversight Board

Duke Energy North America L.L.C., Duke Energy Trading and Marketing, L.L.C., and Duke Energy Merchants, L.L.C. (jointly)

Dynegy Power Marketing, Inc.

El Paso Merchant Energy, L.P.

Enron Power Marketing, Inc. and Enron Energy Services, Inc. (jointly)

Independent Energy Producers Association

Morgan Stanley Capital Group, Inc.

Pacific Gas and Electric Company

Public Utilities Commission of the State of California

Reliant Energy Power Generation, Inc.

Southern California Edison Company

Southern Energy California, L.L.C., Southern Energy Potrero, L.L.C. and Southern Energy Delta, L.L.C.  
(jointly)

Western Power Trading Forum

Williams Energy Marketing & Trading Company

*Appendix B--Timely Intervenors in ER00-3673-000*

California Department of Water Resources

California Electricity Oversight Board

California Power Exchange

Cities of Redding, Santa Clara, and Palo Alto, California, and the M-S-R Public Power Agency (jointly)

City of San Diego, California

**[61,374]**

Duke Energy North America L.L.C., Duke Energy Trading and Marketing, L.L.C., and Duke Energy Merchants, L.L.C. (jointly)

Dynegy Power Marketing, Inc.

Enron Power Marketing, Inc., and Enron Energy Services, Inc. (jointly)

Independent Energy Producers Association

Merrill Lynch Capital Services, Inc.

Metropolitan Water District of Southern California

Modesto Irrigation District

Morgan Stanley Capital Group, Inc.

Northern California Power Agency

Pacific Gas and Electric Company

PPL EnergyPlus, LLC and PPL Montana, LLC (jointly)

Reliant Energy Power Generation, Inc.

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)

Transmission Agency of Northern California

Turlock Irrigation District

Western Power Trading Forum

Williams Energy Marketing & Trading Company

*Appendix C--Parties to the Consolidated Hearing Proceeding*

AES Pacific, Inc.

Arizona Districts

Automated Power Exchange, Inc.

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

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 Dana Point, California

City of Escondido, California

City of Poway, California

City of San Diego, California

City of Vernon, California

City of Vista, California

Cogeneration Association of California and Energy Producers and Users Coalition (jointly)

Duke Energy North America LLC (together with Duke Energy Trading and Marketing, LLC and Duke Energy Merchants, LLC)

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

Metropolitan Water District of Southern California

Modesto Irrigation District

Morgan Stanley Capital Group, Inc.

New York Mercantile Exchange

Northern California Power Agency

Public Utilities Commission of California (California Commission)

Pacific Gas and Electric Company

Pinnacle West Companies

Portland General Electric Company

PPL EnergyPlus, LLC and PPL Montana, LLC (jointly)

Reliant Energy Power Generation, Inc.

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)

The Utility Reform Network

Transmission Agency of Northern California

Western Power Trading Forum

Williams Energy Marketing & Trading Company

#### **Appendix D**

Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities Brief Overview of Conclusions (pp. 1-2 to 1-4)

The report is organized to provide a factual framework for the Commission's use, a section discussing major issues evaluated during the investigation and, finally, a section with options for consideration by the Commission to remedy immediate and longer term problems.

Section 2 of the report finds tight supply and demand conditions existed throughout the west during

most of this summer, with emergency conditions concentrated in California. Broadly speaking,

- Overall demand across the WSCC increased significantly driven by hot weather and load increases that were heat sensitive and that were also driven by increased economic activity. Average summer loads were 11 percent higher in May and 13 percent higher in June from the previous year. Energy consumption also increased across the WSCC by 5 percent in May and approximately 10 percent in June from the previous year. Off-peak demands in the ISO increased

[61,375]

significantly during the summer, in large part to meet increased pumping demands for hydro power facilities, needed for peaking purposes both inside and outside of California. However, peak demand in the ISO area fell slightly, partially reflecting response to emergency declarations and actions.

- Exports increased significantly, with little overall change in the level of imports. As a result, net imports decreased by approximately 3,000 megawatts (MW) from May through August. The ability to increase imports was limited by hydro conditions in the Northwest, which actually declined in July and August, and tight load conditions in other Western subregions. Weather conditions led to increased exports in July and August, corresponding to the decreases in the ISO price cap from \$750 to \$500 in July and then to \$250 in August.

- Outages increased significantly compared with 1999. This was especially true with regard to unplanned outages.

- Increased quantities of demand and supply were left unscheduled in day ahead and hour ahead markets. When loads increased above 35,000 MW in June and at lower levels in July and August, the ISO was forced to buy substantial amounts of power in the form of replacement reserves or out of market purchases.

- Non-hydro generation resources throughout the West were more heavily utilized in 2000 over 1999. Generation from non-hydro resources in 2000 increased by 15.1 percent in May and 24.9 percent in July over 1999 levels. Based on a snapshot of WSCC capacity during a selected high load period, little additional capacity appears to have been available at peak times.

Section 3 of the report finds that wholesale power prices were high throughout the West in the summer of 2000, but their implications were most acutely felt in California. The principal findings of the report on western prices and costs in the summer of 2000 are:

- Prices in the ISO spiked in May and June and average June prices reached record high levels. While an ISO price cap of \$750 existed during the early part of the Summer, prices became highly volatile and the hourly price hit the cap of 3 days in June. Average June prices reached record levels of \$120 in the PX.
- Average prices were lower in July and June, but total costs paid by purchasers in August were higher than June. Caps of \$500 in July and \$250 in August had a dampening effect on high hourly prices, but average prices in August rose to \$166 in the PX after falling below June levels to \$106 in July. The lower caps may have played a role in increasing exports in July and August.
- Prices at other trading hubs in the West generally correlated with California prices suggesting that opportunities to sell at high prices existed in these regions when California prices were high. However, it is not yet clear how scarce supplies were in these regions or to what extent prices outside California were from California imports rather than consumption in other regions. While information for certain weeks in the West indicated supply was scarce, it was not possible to make an overall assessment on scarcity throughout the West without additional information.
- Cost for fuel and environmental compliance (NOx credits) increased significantly in July and August.

Gas prices rose from approximately \$2 per MMBtu early in the year to approximately \$5 per MMBtu in August. Credits to comply with NOx standards rose from \$6 per pound in May to \$35 in August and \$45 in September. Lower caps in July and August reduced the ceiling for market prices while these fuel and environmental costs raised the “floor.” As a result, prices traded over a narrow range.

- Prices in some hours appear to be above those that would have prevailed in a competitive short-term market, if prices were determined from short-term marginal costs.

- Examination of bid patterns in the PX and ISO replacement reserve markets and a review of ISO out of market purchase activity does not suggest substantial or sustained attempts to manipulate prices in these markets. Supply curves bid into the PX show higher bids, on average, when the price caps are lower. However, the increases are not correlated with particular classes of bidders, suggesting that the pattern may reflect increased costs for most participants rather than a pattern of individual bidders or classes of bidders attempting to raise prices intentionally.

Section 4 outlines the statutory and regulatory framework related to energy markets in the West. The report describes the role and policies of the Federal and state economic and environmental agencies in regulating electric utilities in California and the establishment of the ISO and PX, as well as the creation of the Oversight Board. Additionally, this section outlines requirements imposed on the California utilities by the California Commission.

Section 5 discusses the issues that were raised as possibly causing the high prices of this summer. These fall into three general categories: (a) competitive market forces; (b) market

[61,376]

design problems; and (c) market power. The data clearly show that a general scarcity of power in the West and increased costs to produce power were factors causing these high prices. It is also clear that existing market rules exacerbated the situation and contributed to the high prices. The data also indicate some attempted exercise of market power, if the standard of bidding above marginal cost is used, and some actual market power effects, to the extent that prices, at least in June, were significantly above competitive levels. The prices, at least in June, were significantly above competitive levels. However, the data do not isolate specific exercises of market power or suggest that the exercise of market power was more important than other primary explanatory factors.

Section 6 provides a range of options to address the problems identified in this report. Staff also attempts in this section to provide the possible benefits and drawbacks of various options.

The investigation was conducted on an expedited basis so there was not enough time to address all issues in depth. This report is intended to provide the Commission with “the big picture.”

## **Appendix E**

### **Analysis of the Commission’s Retroactive Refund Authority Under the Federal Power Act**

#### **I. Executive Summary**

Section 206 of the Federal Power Act authorizes refunds if the Commission finds existing rates to be unjust or unreasonable. However, that authority is limited to the period from the refund effective date through 15 months thereafter. The Commission has the discretion to determine that such refunds would not be in the public interest in individual circumstances.

The issue of retroactive refunds was expressly considered by Congress in 1935 and again in 1988. In 1935, Congress rejected a provision that would have given the Commission authority to order refunds for any amounts found to be unreasonable or excessive. Instead, the 1935 Act authorized the Commission to

change existing rates (as distinct from Section 205 authority to suspend proposed rate increases) prospectively only-*i.e.*, refund relief was available only after the Commission found that existing rates were unjust or unreasonable. The amendment to Section 206 enacted in the 1988 Regulatory Fairness Act permitted limited retroactive refund authority-*i.e.*, from the refund effective date forward.

Key court precedent interpreting the FPA (and the Natural Gas Act, which contains relevant parallel provisions to the FPA) articulates the filed rate doctrine and the rule against retroactive ratemaking. The filed rate doctrine forbids a regulated entity from charging rates for its services other than those properly filed with the appropriate regulatory authority. In the area of Federal electricity regulation, this doctrine is founded on the requirements in Section 205 of the FPA that rates for jurisdictional services must be just and reasonable and must be on file with the Commission. The precedents on the rule against retroactive ratemaking provide that, except for certain limited circumstances (*e.g.*, rates inconsistent with the filed rate; legal error by the Commission in approving rate changes), the Commission does not have authority to order retroactive rate changes.

While there is no Commission or court precedent on the applicability of the filed rate and retroactive ratemaking doctrines to market-based rates, the provisions of Sections 205 and 206 make no distinction between cost-based and market-based rates. The refund provisions of Sections 205 and 206 of the FPA thus would appear to apply equally to both cost-based rates and market-based rates. Similarly, the filed rate and retroactive ratemaking doctrines, which derive from the requirements of Sections 205 and 206, would appear to apply equally to cost-based and market-based rates.

## II. Legal Analysis of Refund Authority

### A. Statutory Provisions

The Commission's statutory authority to order refunds is specified in Sections 205 and 206 of the FPA. Section 205 addresses rate changes proposed by the public utility providing the service in question; Section 206 addresses rate changes initiated by a complainant or the Commission.

#### 1. Section 205

Section 205(a) provides that all rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is declared to be unlawful.<sup>97</sup>

[61,377]

Section 205 also requires that, absent waiver, a public utility filing any changes in its rates, charges, classifications, or services must provide at least 60 days' prior notice, and permits the Commission to suspend the effectiveness of any such change for a period no longer than five months. Section 205(e) provides that the Commission "upon completion of the hearing and decision may by further order require such public utility or public utilities to refund, with interest, to the persons in whose behalf such amounts were paid, such portion of such increased rates or charges as by its decision shall be found not justified." Thus, refunds under Section 205 are limited to the period beginning with the allowed effective date of the proposed rate change and are also limited to the difference between the proposed increased rate and the pre-existing rate.

Section 205 does not, on its face, provide the Commission authority to order refunds for periods prior to the effective date of the proposed rate change. But, as discussed in Section C.2., *infra*, the Commission may, for example, condition its acceptance of a Section 205 formula rate filing on the Commission retaining the authority under Section 206 to, at a later date, retroactively order refunds with respect to certain costs charged through the formula.

## 2. Section 206

Section 206 provides that if, upon complaint or upon its own motion, the Commission finds that existing rates, charges or classifications are unjust, unreasonable, or unduly discriminatory or preferential, it must determine, and order implementation of, a just and reasonable rate. In 1988, in the Regulatory Fairness Act (RFA),<sup>98</sup> Congress substantially revised Section 206 to permit limited authority to order retroactive refunds of rates found to be unjust and unreasonable. Under Section 206, as amended by the RFA, upon instituting a proceeding under Section 206, the Commission must establish a refund effective date. In the case of a proceeding instituted upon complaint, the refund effective date cannot be earlier than the date 60 days after the filing of such complaint nor later than 5 months after expiration of such 60-day period. In the case of a proceeding instituted upon the Commission's own motion, the refund effective date cannot be earlier than the date 60 days after publication by the Commission of notice of its intention to initiate such proceeding, nor later than 5 months after the expiration of such 60-day period. At the end of any such proceeding, the Commission may, in its discretion, order refunds if it finds that the existing rate is unjust, unreasonable or unduly discriminatory or preferential. Possible refunds are limited to the period from the refund effective date through a date 15 months after such refund effective date and are also limited to the difference between the rate charged and the rate determined to be just and reasonable.

On its face, Section 206 does not provide the Commission authority to establish a refund effective date that is earlier than 60 days after the date that a complaint is filed or the Commission investigates an investigation. Further, Section 206 does not contain any provision authorizing the Commission to order refunds for periods prior to the refund effective date. Therefore, Section 206 does not expressly afford retroactive refund relief for rates covering periods prior to the filing of a complaint or the initiation of a Commission investigation even if the Commission determines that such past rates were unjust and unreasonable.<sup>99</sup>

### B. The Legislative History of Section 206

The FPA as originally enacted in 1935 permitted the Commission to order refunds in Section 206 proceedings prospectively only, *i.e.*, prospectively from the date of the Commission's decision. While the originally proposed bill that led to the 1935 FPA contained a provision which would have allowed the Commission to order retroactive reparations, this provision was eliminated from the final bill while in committee. Thus, the FPA as enacted in 1935 allowed the Commission to change unjust or unreasonable rates, upon complaint or on its own motion, on a prospective basis only. In 1988, the Regulatory Fairness Act amended Section 206 of the FPA to permit specifically limited retroactive refund authority.

#### 1. The 1935 Act

The originally proposed bill that led to the 1935 FPA had contained a provision (Section 213) which would have allowed the Commission, upon complaint, to "order that the public utility make due reparation . . . with interest, for amounts charged by an electric utility which were thereafter found to be unreasonable or excessive." S. 1725, 74th Cong., 1st Sess. at

[61,378]

43 (1935).<sup>100</sup> This provision was eliminated from the final bill while in committee, as it was considered appropriate for a state utility law, but not "applicable to one governing *merely wholesale transactions*." S. Rep. No. 621, 74th Cong., 1st Sess. 20 (1935) (emphasis added). Based upon the foregoing, it is apparent that Congress drew a distinction between retail and wholesale electric rate regulation as to the authority required by a regulatory agency to adequately protect consumers of electric energy. The reason underlying this distinction was not explicitly stated when the legislation was reported out of committee. Nonetheless, certain testimony from the hearings held in connection with the legislation sheds some light on this subject, as set forth below.

John E. Benton, General Solicitor of the National Association of Railroad and Utility Commissioners

(NARUC) appeared before the House committee on behalf of his organization and argued for the elimination of Section 213. *Public Utility Holding Companies; Hearings on H.R. 5423 Before the House Comm. On Interstate and Foreign Commerce, 74th Cong. 1st Sess. 1684-1685 (1935)* [hereinafter cited as *House Hearings*]. Mr. Benton stated:

The next amendment, we ask that Section 213, beginning on page 118, be stricken out.

That is the reparation provision brought in from the Interstate Commerce Act. It provides that if service taken has been charged for at an unreasonable or excessive rate, and if within 2 years an application is made to the Commission, it may disapprove the rate charged and fix a reasonable rate, and require the selling utility to make due reparation to the complainant.

That is an entirely proper provision in a railroad statute. When a man goes to the railroad station with a load of goods to ship somewhere he has to ship at the rate that is fixed in the tariff. He must make the shipment then; and he ought to be able to come thereafter to the Commission and show that he was required to pay an unreasonable rate, if it was unreasonable, and to ask for a determination of a reasonable rate and get reparation that is due him for any overpayment. That is perfectly proper. But this bill relates only to service between the wholesale generating or production company and the distributing utility. We question whether the public interest will be served by giving any company the right to go ahead receiving service at the established rate for 2 years, and then to bring a complaint before the Federal Commission that the rate has been unreasonable. If the provision were that the reparation might run after the complaint was made, it would be more reasonable. But to allow the company to take service for 2 years with no question raised and then to allow it to come in and file a complaint, we believe, is not reasonable. We ask that the provision be stricken out or that it be limited to a recovery of reparation after the complaint is filed.

*Id.*

Whether the distinction drawn by Congress between wholesale and retail rate regulation was based on the relative volume of wholesale and retail sales existing at the time is unclear. Commissioner Clyde L. Seavey of the Federal Power Commission testified in support of the bill and discussed generally the need for Federal regulation of wholesale rates. *House Hearing, supra*, at 420-25. Commissioner Seavey testified that more than 17 percent of the total electric energy generated at that time was transmitted interstate, and that of this 17 percent, “practically all of it is wholesale in nature.” *Id.* at 420-21.

Now, in the electric energy field, at the present time the movement of interstate transmission is over 17 percent. That, however, in percentage does not in either case indicate the full measurement of the need of regulation. *A larger or a smaller percentage does not spell very much and that is not advanced at this time by the Commission as urging that regulation is more than it is in the smaller percentage*, but it is interesting to note, I think, that there is a very substantial movement of interstate energy at the present time.

*Id.* at 420 (emphasis added).

Based upon the foregoing, it appears that Section 213 was included in the proposed legislation submitted to Congress by the Federal Power Commission as a standard utility law

[61,379]

provision borrowed from the Interstate Commerce Act. It further appears that Congress accepted the argument set forth by the General Solicitor of NARUC that wholesale customers of electric utilities should not be permitted to accept service for up to two years without complaint and thereafter be permitted reparations covering that period. However, Congress did not explicitly accept the General Solicitor’s alternative suggestion that the time period for recovery of reparations should commence with the filing of the complaint, and instead eliminated Section 213 entirely. As discussed *infra*, this resulted in the courts

later concluding that Congress intended that the Commission have authority to only grant relief in a Section 206 proceeding prospectively from the date of its order,<sup>101</sup> and it also led to Congress providing limited retroactive refund authority in the RFA of 1988.

## 2. *The Regulatory Fairness Act of 1988*

The Senate Report on the RFA<sup>102</sup> contrasted the Commission's refund authority under Sections 205 and 206. It noted that Section 205 proceedings on average required one year for resolution and that final decisions by the Commission are retroactive to the effective date of the rate increase. With respect to Section 206, the Senate Report stated:

Section 206 of the FPA allows the Commission, on its own motion or pursuant to complaint, to set a "just and reasonable rate" if it finds the rate in effect to be unlawful. Under existing law, a rate reduction under Section 206 differs from a rate increase under Section 205 in two important ways. First, a motion or complaint for rate reduction does not take effect automatically after a given period of time as does a request for rate increase. Second, under Section 206 a rate reduction is prospective only.

Resolution of Section 206 proceedings requires two years on average. One probable reason for the longer period needed to resolve such proceedings is that public utilities have no incentive to settle meritorious Section 206 complaints since any relief is prospective. Under present law, public utilities keep revenues collected during the pendency of a Section 206 proceeding, even if those revenues are subsequently determined to be excessive. H.R. 2858 would correct this problem by giving FERC the authority to order refunds, subject to certain limitations. [<sup>103</sup>]

Thus, the RFA was intended to correct the problem of public utilities engaging in dilatory behavior in Section 206 proceedings in order to delay the effectiveness of proposed, presumably lower, rates. The RFA did so by giving the Commission the authority to establish a refund effective date and make an existing rate subject to refund during the pendency of a Section 206 proceeding for a period of up to 15 months from the refund effective date (longer if the public utility is found to have engaged in dilatory behavior during the hearing).

The Senate Report also explains that the burden of proof was unchanged by the RFA, *i.e.*, the Commission or a complainant has the burden of proof to show that an existing rate, charge or related provision is unlawful and that the proposed rate is just and reasonable.<sup>104</sup>

The Senate Report also states that the RFA was intended to give the Commission the discretion needed to deal with individual circumstances in which refunds would not be in the public interest:

As passed by the House of Representatives, H.R. 2858 required refunds to be paid subject only to a narrowly drawn public interest exception. The Committee amended the House-passed bill to make the granting of refunds under Section 206 discretionary so as to parallel the refund provision of Section 205 of the Federal Power Act. The Committee recognizes that it may not be appropriate in all instances to order refunds in the event that it is determined in a proceeding under Section 206 of the Act that rates or charges are not just and reasonable.

The Committee intends the Commission to exercise its refund authority under Section 206 in a manner that furthers the long-term objective of achieving the lowest cost for consumers consistent with the maintenance of safe and reliable service.

\* \* \*

The Committee is aware that there may be challenges to power pooling and system integration agreements brought under Section 206 of the Federal Power Act in which refunds might not be appropriate, for example, where the issue relates to cost allocation among utilities, and the bill as reported by the Committee is intended to provide the Commission with the discretion needed to

[61,380]

deal with individual instances in which refunds would not be in the public interest.

In determining if a refund may adversely affect the public interest in the case of power pool agreements, the Committee expects the Commission to consider whether, and the extent to which, a refund would adversely affect decisions made on the basis of energy pricing provisions of such pooling agreements or will impose a substantial burden on the pool in comparison with the benefits of refunds to consumers.

In addition to certain situations involving power pooling, there may be others in which the public interest would not be served by requiring refunds under Section 206. Because the potential range of these situations cannot be fully anticipated, no attempt has been made to enumerate them here. In any case, the Committee generally expects the Commission to grant refunds under Section 206 with comparable frequency to its granting of refunds under Section 205.<sup>105</sup>

Thus, the Commission is given the discretion to determine whether, for example, a public utility's financial viability and ability to serve customers might be jeopardized if very large refunds were ordered.

### C. Court Precedent

Two court doctrines have arisen from the courts' interpretations of the limitations of Sections 205 and 206 of the FPA: the filed rate doctrine and its corollary, the rule against retroactive ratemaking.

#### 1. Key Court Precedent Involving the Filed Rate Doctrine Under the FPA and Natural Gas Act

The filed rate doctrine "forbids a regulated entity [from] charg[ing] rates for its services other than those properly filed with the appropriate regulatory authority." *Arkansas Louisiana Gas Co. v. Hall*, 453 U.S. 571, 577 (1981). In the area of federal electricity regulation, this doctrine is founded on the requirements in Section 205 of the FPA that rates for jurisdictional services must be just and reasonable and must be on file with the Commission. The considerations underlying the rule are "preservation of the agency's primary jurisdiction over reasonableness of rates and the need to insure that regulated companies charge only those rates of which the agency has been made cognizant." *City of Cleveland v. FPC*, 525 F.2d 845, 854 (D.C. Cir. 1976); see also *Montana-Dakota Utilities Co. v. Northwestern Public Service Co.*, 341 U.S. 246, 251-52 (1951).

In cases involving the Commission, the D.C. Circuit has explained that:

[v]arious reasons have been offered in support of the filed rate doctrine, and its corollary prohibiting the regulatory agency from altering a rate retroactively. Most recently, the Court justified the doctrine as necessary to enforcement of the underlying statute (*Maislin*, 110 S. Ct. at 2769), in that case the Interstate Commerce Act. The Court has also described the considerations underlying the doctrine as " 'preservation of the agency's primary jurisdiction over reasonableness of rates and the need to insure that regulated companies charge only those rates of which the agency has been made cognizant.' " Opinions of this court have cited "necessary predictability" as "the whole purpose of the well-established 'filed rate' doctrine. . . ." In the context of the Interstate Commerce Act, the Supreme Court has indicated that the doctrine fulfills "the paramount purpose of Congress" of preventing "unjust discrimination." Other courts of appeals have described the doctrine as intending "to prevent discriminatory rate payments" and as "reflecting a statutory bias in favor of retroactive rate reductions but not retroactive rate increases."

Whatever the justification, it is generally agreed that with respect to the Federal Power Act, the filed rate doctrine rests on two provisions: Section 205(c), which requires utilities to file rate schedules with the Commission, and Section 206(a), which allows the Commission to fix rates and charges, *but only prospectively* [emphasis added]. [<sup>106</sup>]

The D.C. Circuit further explained that as the filed rate doctrine and rule against retroactive ratemaking “relate to purchasers, their guiding concern is ‘[p]roviding the necessary predictability,’ allowing ‘purchasers of gas to know in advance the consequences of the purchasing decisions they make.’ ”<sup>107</sup>

[61,381]

## 2. Key Court Precedent Involving the Rule Against Retroactive Ratemaking Under the FPA

Except for certain limited circumstances discussed below (formula rates, legal error by the Commission), the courts have consistently held that under the FPA, the Commission does not have authority to order retroactive rate decreases. *See FPC v. Sierra Pacific Power Co.*, 350 U.S. 348, 353 (1956); *Public Service Co. of New Hampshire v. FERC*, 600 F.2d 944, 957 n.51 (D.C. Cir. 1979), *cert. denied*, 444 U.S. 990 (1979).

In a United States Supreme Court opinion addressing the Federal Power Commission’s lack of authority to order reparations under Section 205(a), the dissent (which concurred with the court’s conclusion that the FPA does not authorize reparations under Section 205(a)) stated:

We face at the outset the contention that this section confers on the Federal Power Commission authority to award reparations for unreasonable rates collected in the past. Federal railroad rate legislation gave such a power to the Interstate Commerce Commission. (citations omitted). But it was not given to the Federal Power Commission. It was withheld deliberately. *See* S. Rep. No. 621, 74th Cong., 1st Sess. 20. Wholesale consumers of electric energy were apparently considered, as a rule, adequately protected by the provisions of the Act authorizing the Commission to grant prospective relief and, in certain circumstances, to order refunding of sums accumulated during the pendency of rate proceedings. §§205(e), 206(a), 49 Stat. 852, 16 U.S.C. §§824(d)(e), 824(e)(a).

*Montana-Dakota Utilities Co. v. Northwestern Public Services Co.*, 341 U.S. 246 at 257-58 (1951), (Frankfurter J., dissenting on other grounds).

As the D.C. Circuit in *City of Piqua* stated:

In essence, the rule against retroactivity is a “cardinal principle of ratemaking [:] a utility may not set rates to recoup past losses, nor may the Commission prescribe rates on that principle.” [citation omitted] . . . The retroactive ratemaking rule thus bars utility refunds for past excessive rates, or the Commission’s retroactive substitution of an unreasonably high or low rate with a just and reasonable rate.

*City of Piqua v. FERC*, 610 F.2d 950, 954 (D.C. Cir. 1979).

There are, however, some limited circumstances under which the Commission can order refunds for past periods. For example, where the Commission has conditionally accepted for filing a formula rate (such acceptance is subject to the condition that the Commission may, at a later date, retroactively order refunds with respect to certain costs impermissibly charged through the formula) and the utility has charged impermissible costs through the formula, or where the rates charged were contrary to the filed rate, the Commission may order refunds. *See, e.g., Appalachian Power Co.*, 23 FERC ¶61,032, at p. 61,088 (1987). The Commission may also be able to order refunds as a remedy to correct legal errors found by an appellate court upon judicial review of a Commission order on a requested rate change. *United Gas v. Callery Properties*, 382 U.S. 223, 229 (1965) (while the Commission has no power to make reparation orders, its power to fix rates being prospective only, it is not so restricted where its order, which never became final, has been overturned by a reviewing court); *Reynolds Metals Co. v. FERC*, 777 F.2d 760, 763 (D.C. Cir. 1985); *see Public Utilities Commission of the State of California v. FERC, et al.*, 988 F.2d 154, 161-162 (1993) (allowing pipeline to seek retroactive recovery of costs based on court reversal of FERC order, citing “general principle of agency authority to implement judicial reversal”). In *Office of Consumers*

*Counsel v. FERC*, 826 F.2d 1136 (D.C. Cir. 1987), the court held that where the Commission had committed legal error in failing to order rate relief to consumers,<sup>108</sup> rate relief dating back to the date of the Commission's error would not violate Section 5 of the NGA<sup>109</sup> since this would place consumers in the same position they would have occupied had the error not been made.<sup>110</sup> See also *Tennessee Valley Mun. Gas Assn. v. FPC*, 470 F.2d 446, 453 (D.C. Cir. 1972) (granting of refunds did not violate anti-reparations language in the statute

[61,382]

which was designed to protect established expectations under legally established rate schedules; one "cannot claim justifiable reliance or protectable expectations based on [Commission] action which was illegal").

*D. Applicability of the Refund Provisions of Sections 205 and 206 and the Filed Rate and Retroactive Ratemaking Doctrines to Market-Based Rates*

No distinction between cost-based and market-based rates is made in the FPA. Indeed, the statute itself does not dictate or even indicate how the Commission is to establish rates. Nor have courts found the Commission to be "bound to the use of any single formula or combination of formulae in determining rates." *FPC v. Hope Gas Co.*, 320 U.S. 591, 602 (1944); see *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 310 (1988) (same). Section 205(c) of the FPA is clear, however, that all rates and charges for jurisdictional transactions must be on file with the Commission. Further, a Commission-approved rate, whether cost-based or market-based, may not be changed, except as provided by Sections 205 and 206 of the FPA. The refund provisions of Sections 205 and 206 of the FPA thus would appear to apply equally to both cost-based rates and market-based rates. Similarly, the filed rate and retroactive ratemaking doctrines, which derive from the requirements of Sections 205 and 206, would appear to apply equally to cost-based and market-based rates. There is no court or Commission precedent that addresses the question directly, however.

**William L. MASSEY, Commissioner**, *concurring*:

Today the Commission takes a step toward restoring confidence that wholesale markets in California can produce just and reasonable prices and consumer benefits. I am concurring on this proposed order, and want to make a number of points.

First, our order finds that the California wholesale market has produced wholesale prices for electricity that are unjust and unreasonable, and that remedies are necessary. On August 23d, in voting on the complaint filed by San Diego Gas & Electric, I reached this conclusion and set forth my opinion in a separate written statement. Although I have maintained an open mind on all issues during the course of our subsequent investigation, I am convinced that any reasonable interpretation of the record now before us today leads to this same conclusion.

Second, our order moves in the right direction toward remedying the problems in California's electricity market. It correctly identifies the problems that must be addressed going forward to ensure just and reasonable rates and protect consumers. The over reliance on spot markets, underscheduling leading to high prices in the real time markets, and the lack of a demand response are clearly areas that must be dealt with effectively, and our order proposes remedies in each of these areas. I am pleased that our order requires the ISO and PX to reconstitute their governing boards with independent members and abolishes the so-called stakeholder boards. Today's order eliminates the state-imposed requirement that the three California utilities sell into and buy from the PX, and I support the ending of this so-called buy/sell requirement.

Third, our order proposes price mitigation going forward. No bid in excess of \$150/MWh will set the market clearing price in the ISO and PX auctions. Sellers may bid above this level and receive their bid if they are dispatched, but they will not set the price that all generators will receive and must report their bid to the Commission.

And fourth, from October 2, 2000 going forward, purchasers may be entitled to refunds for any unjust and unreasonable wholesale prices that may be charged over the following 24 months.

In some of these areas, however, I continue to advocate a more aggressive approach. One of these is forward contracting. Our order finds that there has been an over reliance on spot markets in California, and that consumers have suffered from this. We rightly focus attention on the importance of forward contracts as a way for both buyers and sellers of power to hedge the risk of volatility in the ISO and PX spot markets, and we encourage state policymakers to remove unnecessary barriers to forward contracting. Our order says that we expect public utility sellers to offer a full range of forward contracts covering both short and long-term periods of time. I agree with these conclusions, but would like comment from parties to this proceeding on whether the Commission's final order should take additional steps to "kick start" the market for forward contracting.

Should we, for example, require sellers during the two-year mitigation window to forward contract with California load serving entities a certain percentage of their supply? In a recent pleading styled an Offer of Settlement, the California ISO suggests a forward contracting requirement of 70%. Should the Commission require a certain amount of forward contracting as a temporary measure to mitigate market power in spot markets? Should such an obligation be placed on sellers or buyers, or both? Should the Commission specify a certain level, or does this unnecessarily intrude into

**[61,383]**

business arrangements? During our recent hearing in San Diego, Professor Frank Wolak, Chairman of the ISO's Market Surveillance Committee, suggested that the Commission define a forward contract of 18-24 months duration, set a just and reasonable price for such a contract, and attempt to reach agreement with the California PUC that purchasing such a contract would be deemed prudent. I would appreciate comments on the viability of this concept as well.

Another issue on which I would like comment from parties is our order's proposed \$150/MWh ceiling on the market clearing price. Is this a sufficient consumer protection measure? This ceiling would last for 24 months. Our order concludes that in some hours, and particularly at high load levels when there is an imbalance between supply and demand, flawed market rules and a flawed market structure allow the exercise of market power that must be effectively mitigated. Under the proposed \$150 ceiling, a generator that bids higher and is dispatched can receive the higher bid, so this is not a hard \$150 cap, but this higher bid will not set the market clearing price, and the generator must file a report to allow the Commission to evaluate the bid. This \$150 "soft cap" is designed to accommodate the marginal running costs for a combined cycle generating unit, dispatched roughly one third of the time, with an investment payback period of 5 years. It seems to me that these same assumptions, coupled instead with a 10 year payback period, might justify a \$120 ceiling. Or the price of natural gas could fall, justifying a somewhat lower ceiling.

I would like comment on whether this soft cap is a good idea. Will it be an effective market power mitigation measure? Has the Commission balanced competing interests reasonably in choosing the \$150 level? Should such a cap vary at different load levels or with the price of natural gas or Nox credits? Commenters should keep in mind that today's order proposes to eliminate the ISO's purchase price cap authority, which is the only wholesale price mitigation protection customers have had, so the \$150 soft cap should be evaluated with this in mind. Would a 24 month hard cap be more appropriate or would it deter entry of much-needed generation.

Our order deals with other important issues. With respect to the issue of retroactive refunds for last summer when prices were very high, our Office of General Counsel has prepared a legal memorandum that concludes that the Commission has no authority to order refunds for any period of time before October 2, 2000. I realize that this is an issue of utmost importance to the residents of California. This agency must act within the authority delegated by law, and the Congress has not given us this authority, according to our

legal staff. Today's order concludes, however, that the Commission would consider any equitable remedies that parties wish to propose in this area. I interpret this language among other things to invite comment on the extent of the Commission's authority in the area of refunds. Has our legal staff reached the correct conclusion? Are there legal precedents or arguments that we have overlooked or misconstrued? This is such an important issue that we should use the comment period to ensure that we reach the correct conclusion with respect to the scope of our refund authority.

Finally, our order attempts to lay out the areas of concern that we believe are our responsibility under the Federal Power Act, including the justness and reasonableness of wholesale prices and ensuring the independent management of the transmission grid. But for the wholesale market to function well, California needs new generation and transmission capacity, and the siting of new facilities is clearly within the jurisdiction of the State of California. I know that I am stating the obvious, but I just want to make the point that we share jurisdiction over electricity regulation with the State of California. We must do our part, and the state must do its part to ensure that customers benefit from competition. I look forward to working with the State of California to ensure that consumers do in fact benefit from competitive markets that produce just and reasonable prices. That is what today's order is all about.

In conclusion, this is not a perfect order. I seek comment on whether we should take a more aggressive approach to certain issues. Going forward, this Commission must take each and every measure necessary to protect consumers from unjust and unreasonable prices. We must ensure that consumers benefit.

**Curt L. HQEBERT, Jr., Commissioner, concurring:**

#### *Introduction*

As much as I would like to offer a recitation that would be more to the liking of San Diegans, and sit as the most popular member of this Commission, my oath, taken almost exactly three years ago on this date, requires me to regulate in a forthright and intellectually honest fashion. We must provide supply and deliverability opportunities in America and, especially, in California. Worse than high prices, reliability concerns for the good people of California must be a priority.

**[61,384]**

Recent events demonstrate two things. California wholesale electricity markets require reform. And California ratepayers deserve relief.

In today's order, the Commission attempts to accomplish both tasks. Frankly, in my judgment, it is not altogether clear whether the Commission has moved in the direction of achieving its stated goals of reforming California markets and helping California ratepayers. If it were up to me, today's order would be much, *much* different.

Nevertheless, on balance, today's order appears to be a step in the right direction. For this reason, I hesitantly concur. However, there remains much uncertainty as to the practical effect of various remedial measures adopted in today's order. I can support the order only because it does not represent the last word; it is merely a "proposed" order. A technical conference and a round of comments from the public will follow. If, after listening to comment on the subject, I am convinced that the Commission has moved in the wrong direction-and I am perilously close to that conviction right now-I will not be hesitant to upset the basket of remedial measures adopted today.

I write separately to present for comment the basket of remedial measures I would adopt, if given the chance. I agree with today's order to the extent it explains that California electricity markets suffer from serious structural defects that inhibit the operation of a competitive market. I also agree that the current situation requires "decisive" action; otherwise, California markets will not move toward the goal we all agree on. The Commission needs to act now to ensure that energy suppliers have an incentive to enter capacity-starved California markets, that local 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 simply disagree with today's order with respect to its selection of corrective measures. Some will help; others will hurt. Others not selected would have helped more. The Commission should have stopped with corrective measures designed to remove impediments from the operation of a competitive market. Instead, unfortunately, it decided to go farther and adopted additional measures that prescribe with tremendous specificity how market institutions and market participants should act during the transition period to a fully competitive market. The majority of the Commission believes that various prescriptive measures will ease the pain felt by market participants during what it believes will be a two-year transitional period.

I believe, however, that the Commission's overreaching will only prolong the transition period for an indefinite period. If the Commission were truly committed to the competitive ideals articulated in today's order, it would have taken "decisive" action to ensure that California markets achieve those ideals as quickly as possible. Now is not the time for timidity. California ratepayers will benefit from the restructuring of the California energy market *only* when that market is allowed to operate without artificial restraints designed by regulators who believe that they know best how to serve energy customers.

I now proceed to explain the basket of remedial measures I would adopt to address the California electricity situation. I then explain those measures adopted by the Commission that I would not have adopted. I finish with a discussion of the Commission's attitude toward refunds.

#### *Remedial Measures I Would Adopt*

##### *1. Eliminate All Price Controls*

Today's order is filled with repeated references to the perceived need for "price mitigation." As a general matter, I find the concept of "price mitigation" to be an offensive one. Government should not be mitigating prices. It is ill-equipped to do so; its efforts invariably back-fire to the detriment of consumers. Rather, market participants-primarily energy suppliers and energy consumers-should be entrusted with the ability and the responsibility to mitigate their price exposure as they deem best.

This is a subject that I have written about in numerous dissents and concurrences over the past three years. Events in California demonstrate that my position is not merely academic or philosophical. In a report dated September 6, 2000, the Market Surveillance Committee of the California ISO concluded that price caps have little ability to constrain prices. Specifically, it noted that monthly average energy prices in California during June of this year, when the price cap was \$750/MWh, were lower than monthly average energy prices during August of this year, when the price cap was \$250/MWh-even though energy consumption was virtually the same in both months.

Moreover, the Commission's own Staff Report suggests that there is a direct correlation between lower price caps and higher consumer prices. Specifically, it finds that decreases in the ISO price cap this past summer were matched by increases in exports of electricity out of California during the same period. The resulting decrease in net imports, historically relied upon by California, is one of the principle

[61,385]

reasons for the increase in wholesale electricity prices.

For these reasons, I am gratified that the Commission today decides to reject the price cap proposed by the PX and the purchase cap amendment filed by the ISO. I agree with the rest of the Commission that the price cap has served to keep sellers out of California markets and has inhibited the incentive of electricity purchasers to engage in forward contracting and thus hedge against price volatility and uncertainty.

Unfortunately, the Commission does not stop here. Instead, it proceeds to take additional "mitigation"

action that belies its stated intention to allow competitive markets to send price signals to suppliers and customers.

## *2. Abolish the Single Price Auction*

The Commission abandons a hard cap and imposes a soft cap in its place. This is accomplished through the Commission's modification of the single price auction. In today's order, the Commission creates two distinct categories of bids into the PX and ISO. Sellers bidding below \$150/MWh will be subject to little scrutiny. Sellers bidding in excess of the \$150 threshold, however, will be subject to tremendous scrutiny. Today's order explains in considerable detail all of the information the PX, ISO, and each seller must report for each bid in excess of \$150. Moreover, the order states ominously that the purpose of the enhanced reporting requirements is not simply to monitor market behavior. Rather, it explains that the Commission will use this information "to adjust transaction prices, if necessary, to establish just and reasonable rates."

Thus, to me, the practical effect of today's modification to the single price auction is to clearly disfavor all bids in excess of \$150. While the order states that the Commission is not preventing a supplier from bidding in excess of that number and receiving its bid, I doubt that suppliers will be anxious to take advantage of that opportunity and to incur the Commission's wrath. I ask for comment as to whether my doubts are shared by the industry.

I would simplify matters considerably. I would not select an arbitrary \$150 figure and leave it in place for an equally arbitrary 24-month period. Instead, I would do what numerous participants in our California proceeding have been asking us to do-eliminate the single price auction altogether.

Despite its length, today's order is surprisingly silent as to the merit of abandoning the single price auction. (This is one of the remedial options identified in the Staff Report.) I fail to perceive any compelling reason why any bid should set the price for the entire market. If the market clearing price for the final increment of needed capacity is, say, \$100 MWh, why should a supplier who bid a lower figure receive the same value as that afforded to the supplier of higher-priced increment? Similarly, if the market clears in excess of \$100, why should that clearing price set the market price?

My preference is that sellers in California be paid what they bid, regardless of what that bid is, rather than the market clearing price. I can think of no other action that would be more effective in lowering rates to truly competitive levels.

## *3. Terminate the Mandatory Buy-Sell Requirement in the PX*

This is one topic that the Commission gets right in most respects. Wholesale customers should have the ability to name their own price. The Priceline.Com model is, in its most basic form, applicable to wholesale electricity. Purchasers do not need the government to intercede to limit upside price risk. Rather, purchasers have the ability to do this for themselves, if government does not interfere to limit their ability to take advantage of financial instruments and contracting options.

Today's order concludes that the existing requirement that investor-owned utilities sell all of their generation into and buy all of their requirements from the PX contributes significantly to rates that are unjust and unreasonable. I agree. The Commission correctly removes this encumbrance to trading options. Load-serving utilities should have full opportunity to pursue a portfolio of long- and short-term resources and to reach whatever markets are best suited to meet the needs of their customers.

Unfortunately, in its zeal to promote hedging opportunities-a laudable goal to be sure-the Commission goes too far. I explain later in this statement my objection to the Commission's decision to dictate to market participants how best to manage risk.

## *4. Direct the ISO and PX to Address Remaining Impediments in Their January, 2001 RTO Filing*

Today's order expends many pages addressing numerous other flaws in the California market design.

Specifically, the order discusses reserve requirements, congestion management redesign, reliability and operational measures, governance structures, demand response, balance scheduling, generation interconnection, and market monitoring and mitigation. The Commission requires specific responses to certain of its concerns. It directs market institutions and participants to consider and report back on other concerns.

I am greatly concerned that the Commission, in its desire to appear active and engaged, is

**[61,386]**

greatly undermining the ability of the ISO and PX to make its regional transmission organization (RTO) filing. That filing is due to be filed no later than January 16, 2001-only 2 2 months from now. I have no problem with the Commission identifying its concerns in this order. However, I would ask the ISO and PX to take these concerns into accounts when they make their RTO filing. By asking the ISO and PX to act immediately on some measures, relatively soon (short-term) on other measures, and somewhat more leisurely (long-term) on still other measures, the Commission is greatly inhibiting the ability of the PX and ISO to respond effectively to their RTO filing obligation. The Commission is also hindering, and in some cases pre-judging, its ability to act on that filing once received.

#### *Remedial Measures I Would not Adopt*

##### *1. Modify the Single Price Auction*

I have already explained my preference for abandoning, rather than modifying, the auction rules used by the PX and ISO. If the Commission insists on modifying, rather than terminating, the single price auction, I would offer a different modification.

Specifically, I would start the single price auction for all sale offers at or below \$250 MWh. I would not lower the *de facto* price cap below the figure currently in place and previously approved (over my dissent) by the Commission. The Staff Report indicates (at 6-12) that the existing ISO cap already appears to be too low, and that it comes close to the variable costs (fuel and emissions) of a combustion turbine. The Report continues that a price cap at the existing level is unlikely to be high enough to attract new investment.

If the Commission is insistent that it must have a single price auction dollar figure in place, I would not leave it at that figure for the entire period of the transitional period. Rather, I would escalate that figure 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, will have the incentive to respond *immediately* to the market design flaws identified in today's order. For example, the Commission has no authority to direct the state of California to expedite its siting and permitting procedures, or to drop remaining impediments to forward contracting. A price cap escalator, however, would act to spur all market players to adopt new and badly-needed remedial measures.

##### *2. Disband Stakeholder Boards at this Time*

I have no particular fondness for the stakeholder Governing Boards for the PX and the ISO. As today's order correctly explains, the decision-making process is overly complex, mired in controversy, and prone to excessive influence by special interest groups. In operation, the Boards function as little more than a debating society among various market participants. Their governance structure is no model for how a transmission grid or centralized exchange should be operated. The structure is certainly no model for how a competitive business should be run.

Despite all of my misgivings, I would not proceed, as the Commission does today, to dictate right now how the Governing Boards should be restructured. Governance and independence are topics, I presume, that the ISO and PX are vigorously debating as they prepare their RTO filing. They very well may decide to adopt the independent, non-stakeholder governance structure preferred by the Commission in today's

order. But, then again, they may not. This is ultimately a matter to be addressed by the ISO and PX, after consultation with various market participants, in the first instance and for the Commission to consider only after receiving the California RTO filing.

By insisting upon a non-stakeholder structure right now, the Commission is betraying its principles as articulated in [Order No. 2000](#). The Commission stated its preference for flexibility and initiative. It also indicated that what works well in one region of the country may not work as well in other regions. I have no idea whether the Boards of ISOs in New York, New England, and PJM would have responded any more effectively and independently than the California ISO and PX Boards, had they been presented with similar market problems. Today's order assumes that governance structures in the East would have operated more effectively than the existing governance structure in the West. I would make no such assumption.

Indeed, all of the Commission's articulated concern for independence and effective decision-making merely confirms my belief that by far the most independent and effective governance structure is that found in an independent transmission company. Despite my enthusiasm for a transco, I would not dare suggest that the Commission impose one on California right now in punishment for the conduct of the California Governing Boards this past summer.

Finally, the Commission is needlessly provoking a constitutional show-down. The Governing Boards are the product of legislative decisionmaking. As a practical matter, I doubt they can be replaced in the time frame contemplated in today's order. Moreover, left unexplained is what the Commission intends to do if

[61,387]

the ISO and PX balk at the requirement to adopt immediately a non-stakeholder governance structure. This is precisely the reason why the governance structure should be negotiated and worked out in the context of the collegial RTO process-not determined immediately by regulatory fiat.

### *3. Dictate to Market Participants How Best to Manage Risk*

I share the Commission's enthusiasm for risk management and forward contracting. A prudent utility, I assume, would spread out its risk and procure a diversified portfolio of contracts. This Commission and the California Commission, to the extent possible, should encourage the scheduling of load in forward markets (daily, weekly, monthly, annually, *etc.*) and should discourage scheduling in real-time (spot) markets. California utilities that failed to take advantage of forward contracting options, because of inattentiveness or regulatory inhibitions, were badly burned this past summer when real-time electricity prices sky-rocketed.

Nevertheless, I draw the line at dictating to market participants precisely how much of their transactions to schedule in forward markets and how much to schedule in real-time markets. I have no basis for assessing what an optimal allocation between forward and real-time scheduling should look like. I believe that no single risk allocation portfolio is appropriate for all market participants. And I believe that no market participant should be locked into a particular allocation method once established. This is, ultimately, a decision to be made by market participants based upon their own risk tolerance and their own evaluation of competitive and financial opportunities. (Hopefully, market participants will be able to make such a decision now that the Commission is eliminating the mandatory buy-sell requirement in the PX).

I understand that there is a fine line between managing risk and operating in a reliable manner. The Commission justifiably raises a concern in today's order that underscheduling of load and generation in day-ahead and day-of markets forces the ISO to operate an energy market and places system reliability at risk. However, the answer to this concern is not to compel market participants to schedule 95 percent or more of their transactions in forward markets. Rather, I would prefer to direct the ISO and PX to address the underscheduling issue in their forthcoming RTO filing.

*Refunds*

I choose to close with a discussion of refunds, so as to stress the importance of this issue.

The Commission needs to be honest and forthright with California ratepayers on the subject of refunds. It is a basic premise of responsible government that the American public should know precisely where their elected and appointed officials stand. This is particularly true in California, as the Commission has promised in its orders and in its hearings that it would decide quickly and decisively whether to order refunds.

I believe that the Commission has failed as to this basic responsibility. It is now November 1, and California ratepayers are no closer to a final decision on their claim to refunds for perceived overcharges during the summer. Today's order employs mushy and confusing language on the subject of refunds, indecipherable to all but the most devoted of FERC insiders. I would be more direct.

As for refunds for past periods, today's order concludes that legal authority offers "strong support" for the proposition that the Commission lacks authority to order retroactive refunds. I would not be so equivocal. The Federal Power Act rests on a legislative preference for rate certainty. Refunds and rate revisions, absent a utility filing, are reserved for periods subsequent to the filing of a customer complaint or the initiation of a Commission proceeding. I discern no exception for market-based (as opposed to stated) rates.

I fail to see how the Commission, even if it wanted to order refunds for prices charged to San Diegans during the summer of 2000, could do so in the present circumstances. Neither the Staff Report nor today's order contains any finding that any power supplier exercised market power or otherwise engaged in inappropriate behavior. Indeed, neither the Staff Report nor the order reaches definite conclusions about any seller or category of sellers. In these circumstances, how could the Commission order individual sellers or categories of sellers to make refunds, much less allocate responsibility for refunds among sellers?

Curiously, the Commission does state in a footnote that is willing to consider "other forms of equitable relief" to mitigate the "severe financial consequences of last summer's high prices." Frankly, I do not know what this statement means. If the Commission intends to suggest that it enjoys the power to do indirectly what it cannot do directly-*i.e.*, exercise its considerable powers of persuasion to motivate power suppliers to reimburse buyers in some respect--then I reject that suggestion as legally unfounded.

As for refunds for future periods, today's order informs power suppliers that their sales into California ISO and PX markets are now "subject to refund." I addressed the practical effect of "subject to" language in my concurrence to the August 23 order initiating the

**[61,388]**

Commission's investigation into California markets. [92 FERC at p. 61,611](#). I believe that the inclusion of "subject to" language will act to exacerbate supply deficiencies in California. This is because power suppliers, uncertain whether the Commission later may decide to alter the rate they have charged, justifiably will decide to sell their capacity in markets outside California. This will only accelerate the exodus of power outside California, a factor recognized by the Staff Report as contributing to the summer increase in the wholesale price of electricity.

I also have serious reservations about conditioning market-based rate authorization on maintaining a "subject to refund" obligation through the end of 2002. This has the practical effect of extending the refund protection under Section 206 of the FPA for a total of 27 months of protection. In contrast, Section 206 is explicit that, absent dilatory behavior of the type not present here, refund relief may extend only 15 months from the refund effective date established by the Commission (here, October 2, 2000).

To address credible claims of anticompetitive behavior, I would employ the Federal Power Act as it was drafted and promulgated, not as it arguably should be revised to recognize modern-day power sales. I

continue to believe that the Commission should act vigorously to detect and remedy real abuses of market power. If a complaint or Commission staff-initiated investigation can establish, to the Commission's satisfaction, such an abuse, the Commission should order refunds prospective from the date of that complaint or investigation. By directing the imposition of a "subject to refund" condition on California sellers of power, the Commission now goes beyond the limitations of the FPA by allowing for the potential award of refunds for conduct prior to the filing of a complaint or the initiation of an investigation.

Next Tuesday represents the most political day of our American heritage. It is our birthright as Americans. Today, there is no room for politics. The question is not whether or not I want to give refund relief to California ratepayers. I do, but I want to follow the law. I am certainly not above it.

### *Conclusion*

In conclusion, there is much I like and much I dislike about today's order. I believe that it is important to keep the process moving forward and to inform California ratepayers and officials of our judgments as soon as possible. I look forward to public input. I remain committed to respond to the needs of California ratepayers in a balanced manner that, hopefully, will allow them to enjoy the benefits of a competitive market as quickly as possible.

For all of these reasons, I respectfully concur.

-- Footnotes --

[61,349]

[61,350]

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<sup>1</sup> *San Diego Gas & Electric Company, et al.*, [92 FERC ¶61,172](#) (2000), *reh'g pending* (August 23 Order).

<sup>2</sup> *See Order Directing Staff Investigation*, [92 FERC ¶61,160](#) (2000) (July 26, 2000 Order).

<sup>3</sup> In addition to the 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), the Commission has placed in the record the transcript of the Commission's September 12, 2000 public meeting in San Diego, California, written submissions in response to that public conference, and all reports prepared by the ISO and PX and their market surveillance committees.

<sup>4</sup> Under Section 206(a) of the FPA, if the Commission finds, after hearing, that any rate, charge, or classification for jurisdictional services, or any rule, regulation, practice, or contract affecting such rate, charge or classification "is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order."

[61,351]

In December of 1999, the Commission issued its Order on Regional Transmission Organizations, [Order No. 2000](#). Regional Transmission Organizations (RTOs) can be formed as ISOs or may take another organization form, such as a transco. The Commission's RTO requirements build upon the ISO principles of [Order No. 888](#) and reflect, in large measure, the Commission's experience with the pioneering efforts of ISOs such as the California ISO. The California ISO and its public utility members are required to make a filing in compliance with [Order No. 2000](#) on January 17, 2001.

[61,352]

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<sup>5</sup> Because the market structure and market design remedies ordered herein may take up to 24 months to effectuate, and the refund period permitted by FPA Section 206 is limited to 15 months, the Commission proposes to condition its market rate authorizations for public utility sellers to the ISO and PX on continuing the refund obligation through December 31, 2002.

<sup>6</sup> As of January 1995, retail rates in California were 10 to 11 cents per kilowatt-hour, approaching twice the national average, and rising. *See California Rides the Tiger*, Public Utilities Fortnightly, January 1, 1995, p. 20.

<sup>7</sup> *See* California Commission Decision D.95-12-063 (December 20, 1995), *modified by* D.96-01-009 (January 10, 1996) and D.96-03-022, 166 P.U.R. 4th 1 (California Commission Restructuring Decision).

<sup>8</sup> AB 1890, signed by Governor Wilson on September 23, 1996, California Statutes 1996, Chapter 854 (Restructuring Legislation or AB 1890).

<sup>9</sup> As discussed later in this order, the Commission rejected elements of the proposal dealing with the Oversight Board, and the Board subsequently filed a petition for declaratory order requesting that the Commission declare that a bill pending in the California Senate (SB 96), modifying the Board's duties under the Restructuring Legislation, if enacted, would resolve the Commission's concerns about the Board's role.

<sup>10</sup> The Commission established the principles for ISOs in [Order No. 888](#), and three other ISOs are in operation today: PJM Interconnection, New York ISO, and ISO New England.

<sup>11</sup> *See Pacific Gas and Electric Co., et al.*, [77 FERC ¶61,077](#) (1996) (*PG&E I*); *Pacific Gas and Electric Co., et al.*, [77 FERC ¶61,204](#) (1996) (*PG&E II*); *Pacific Gas and Electric Co., et al.*, [77 FERC ¶61,265](#) (1996) (*PG&E III*). One area of particular concern

[61,353]

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for the Commission was the scope of the Oversight Board's functions. Specifically, the Commission noted that it could not "accept a permanent role for the Oversight Board in the governance or operation of the ISO, or appellate review of ISO Board decisions, because these matters are within our exclusive jurisdiction." See *PG&E II* at p. 61,818.

<sup>12</sup> *Pacific Gas and Electric Co., et al.*, [81 FERC ¶61,122](#) (1997) (October 30, 1997 Order).

<sup>13</sup> Among the four jurisdictional ISOs that are in operation, the Commission has devoted, by far, the most resources to the California ISO, and most of the attention required by the California ISO reflected the difficulties in implementing the requirements of AB 1890 and the impact of those requirements on transmission grid operations and market performance.

<sup>14</sup> See *AES Redondo Beach, L.L.C., et al.*, [84 FERC ¶61,046](#) (1998), *order on reh'g*, [85 FERC ¶61,123](#) (1998) (October 28 1998 Order), *order on further reh'g*, [87 FERC ¶61,208](#) (1999) (May 26, 1999 Order), *order on further reh'g*, [88 FERC ¶61,096](#) (1999), *order on further reh'g*, [90 FERC ¶61,148](#) (2000). See also *California Independent System Operator Corporation*, [84 FERC ¶61,309](#) (1998).

<sup>15</sup> October 28, 1998 Order, [85 FERC at p. 61,462](#).

<sup>16</sup> See May 26, 1999 Order, [87 FERC at pp. 61,801](#) -02 (explaining that the ISO developed a phased approach to the redesign).

<sup>17</sup> [85 FERC at p. 61,463](#).

<sup>18</sup> *California Independent System Operator Corporation*, [86 FERC ¶61,059](#) (1999).

<sup>19</sup> [87 FERC at pp. 61,817](#) -19.

<sup>20</sup> *California Independent System Operator Corporation*, [89 FERC ¶61,169](#) (1999), *reh'g pending*.

<sup>21</sup> Price Movements in California Electricity Markets: Analysis of May-July 2000 Price

[61,354]

[61,355]

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Activity, PX Compliance Unit, September 29, 2000 at 10.

<sup>22</sup> Report of California Energy Market Issues and Performance: May-June 2000, ISO Department of Market Analysis, August 10, 2000 at 13.

<sup>23</sup> Natural gas comprises about 55 percent of California's fuel mix.

<sup>24</sup> Staff Report at 3-21.

<sup>25</sup> The two utilities have reported about \$4.6 billion in unrecovered wholesale costs of which about \$2 billion reflects sales of electricity sold from generation which they still own.

<sup>26</sup> On September 7, 2000, the California Assembly passed SB 970, to address the immediate need for certain additional generating capacity in the State. SB 970 created an interagency task force appointed by the Governor from various California regulatory agencies, related federal agencies, and local governments.

<sup>27</sup> See Electric Utility Week, October 9, 2000, pp. 5-6.

<sup>28</sup> See *infra*, note 2.

<sup>29</sup> *Morgan Stanley Capital Group Inc. v. California Independent System Operator Corporation*, 92 FERC ¶61,112 (2000) (*Morgan Stanley*).

<sup>30</sup> 92 FERC at p. 61,606. (Commissioner Massey dissented on this point.)

<sup>31</sup> The Staff Report concluded that: "Further study of high-priced bidding by individual firms or periods when individual generators were not running would be needed to substantiate any charges of market power abuse." Staff Report at 5-19. The Commission will evaluate any information it receives as part of its review of these markets.

[61,356]

[61,357]

[61,358]

because of the significant amounts of interstate market activity that occurs at these points.

[61,359]

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<sup>32</sup> A single price auction pays all bidders the price paid to the last seller whose output is needed to clear the market (balance supply and demand); often referred to as the market clearing price. Another auction mechanism, often referred to as the “as bid” auction, pays bidders their own bid price if they are selected.

<sup>33</sup> August 23 Order at p. 61,606.

<sup>34</sup> On October 26, 2000, the ISO Board voted to change the ISO bid cap from the current \$250 level to a load differentiated cap, effective on November 3, 2000 or as soon thereafter as can be implemented. Our action in this order freezing the ISO bid cap at the current \$250 level for 60 days, renders the ISO board vote null and void.

<sup>35</sup> As early as the 1970’s, Western utilities began to face the problem of significant regional loop flows resulting from the interstate use of the Western grid and, in the 1990’s, Western utilities agreed on a regional response. *See Southern California Edison Co., et al.*, [70 FERC ¶61,078](#) and 73 FERC ¶61,219 (1995).

<sup>36</sup> California’s import capability is approximately 8,000 MW.

<sup>37</sup> Two of the first trading hubs for wholesale electricity futures were founded at the California/Oregon Border (COB) and at Palo Verde, in Arizona,

<sup>38</sup> *See Staff Report* at 1-3, 3-15 and 3-17.

<sup>39</sup> There are a number of fixes that must be made that are beyond the statutory authority of this Commission. Thus, we also highlight several initiatives that the State of California must undertake to ensure that the high and volatile price scenario of this past summer is not repeated.

[61,360]

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<sup>40</sup> Staff Report at 3-20 and 3-22.

<sup>41</sup> *Id.* at 5-2, 5-3 and 5-6.

<sup>42</sup> Due to reduced water flows in the West, the output of hydropower generation was reduced. For example, hydro output in June 1999 was 16,685 GWh and in June 2000 was 12,808 GWh, a reduction of 3,880 GWh. Staff Report at 2-26.

<sup>43</sup> An Analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Services Markets, ISO Market Surveillance Committee, September 6, 2000 at 13.

<sup>44</sup> We do not seek to eliminate pricing volatility in spot markets. These markets will, as a matter of course, swing in reaction to changes in short-run market conditions that are difficult to predict. What is important is that market participants have the ability to protect themselves from the economic consequences of pricing volatility. In simplest terms, if California IOUs had the option to use forward markets last summer and had chosen to exercise those options to purchase most of their needs, the high spot market prices experienced this summer would have affected only a small portion of the wholesale power costs. We do not mean to suggest that spot prices are always higher than forward market prices. Indeed, because of cooler than expected weather in the east, buyers in PJM that may have locked in prices in forward markets, based on the best information at the time of their decision, ultimately paid more for energy than the price that was available in the spot markets. The critical issue is choice and providing market participants with the tools to access the market in the ways that best serve their needs.

<sup>45</sup> Initially, the PX administered only a Day-Ahead and an hour-ahead (Day-of) spot Market. Later, it added limited forward market products.

<sup>46</sup> Section 368 of AB 1890.

<sup>47</sup> The Staff Report indicates that over the past five years load in California has risen by 5,522 MW while resources have increased only 672 MW. Staff Report at 5-8.

<sup>48</sup> While the IOUs have recently been authorized by the California Commission to use either the PX's forward markets or the bilateral market, the overall restrictions on the

[61,361]

[61,362]

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total amount of forward purchases remain.

<sup>49</sup> PG&E, SoCal Edison, and SDG&E still control 26 percent, 20 percent, and 1 percent, respectively, of in-state generation and purchase power contracts.

<sup>50</sup> The Staff Report reached a similar conclusion. Staff Report at 5-9 and 5-11.

<sup>51</sup> The IOUs own nuclear and hydro generation whose variable operating cost are approximately \$16/MWh (for a nuclear unit operating at 88 percent capacity factor) and no fuel costs for hydro. Dynegy letter dated October 27, 2000.

<sup>52</sup> The PX Day-Of Market is the hourly energy market that is scheduled with the ISO at least 2 hours in advance of real time.

<sup>53</sup> Underscheduling occurs when an entity schedules significantly less energy than its expected actual consumption.

<sup>54</sup> Staff Report at 5-14 and 5-16.

<sup>55</sup> August 25, 2000 Memorandum from Mr. Winter to ISO Board of Governors.

<sup>56</sup> [92 FERC at p. 61,608](#).

<sup>57</sup> We propose 5 percent because this is the maximum amount that the ISO intended to balance in the real-time market for operating the transmission system.

<sup>58</sup> *See, e.g., Indiana Michigan Power Company, et al., 44 FERC ¶61,313, at p. 62,078* (1988).

<sup>59</sup> *See also* Section C3. Balanced Schedules below.

<sup>60</sup> *PG&E II*.

[61,363]

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<sup>61</sup> See *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, 61 *Fed. Reg.* 21,540 (1996), *FERC Statutes and Regulations, Regulations Preambles January 1991-June 1996* ¶31,036 (1996) (*Order No. 888*), order on reh'g, *Order No. 888-A*, 62 *Fed. Reg.* 12,274 (1997), *FERC Statutes and Regulations* ¶31,048 (1997), order on reh'g, *Order No. 888-B*, 62 *Fed. Reg.* 64,688, 81 *FERC* ¶61,248 (1997), order on reh'g, *Order No. 888-C*, 82 *FERC* ¶61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group, et al. v. Federal Energy Regulatory Commission*, 225 F.3d 667 (D.C. Cir. 2000).

<sup>62</sup> 77 *FERC* at pp. 61,816-17; 81 *FERC* at p. 61,453.

<sup>63</sup> See, 77 *FERC* at p. 61,818.

<sup>64</sup> 81 *FERC* at pp. 61,451-53; see also *California Power Exchange Corp., et al.*, 85 *FERC* ¶61,263 (1998).

<sup>65</sup> 85 *FERC* ¶61,264, at p. 62,068.

<sup>66</sup> See *California Electricity Oversight Board*, 88 *FERC* ¶61,172 (1999), *reh'g denied*, 89 *FERC* ¶61,134 (1999), *appeal docketed, Western Power Trading Forum, et al., v. FERC*, No. 99-1532 (D.C. Cir.) (*Oversight Board*).

<sup>67</sup> These state-retail matters included, *e.g.*, state functions assigned to the ISO and PX under state law, matters pertaining to retail electric service or retail sales of electric energy, and open meeting standards and meeting notice requirements.

<sup>68</sup> Staff Report at 6-17.

<sup>69</sup> September 12, 2000 Meeting, transcript at 107, 108 and 127.

<sup>70</sup> "Cal-ISO Asks FERC for Forward-Looking Market Fix," *The Energy Daily*, October 23, 2000, p. 2. See also "Divided Cal ISO Postpones Action on Fixes," *Power Markets Week*, Oct. 9, 2000, pp. 1, 18-19.

[61,364]

[61,365]

[61,366]

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<sup>71</sup> Letter of resignation of Camden Collins, dated July 3, 2000.

<sup>72</sup> California ISO Board of Governors Meeting minutes, June 28, 2000, p. 89.

<sup>73</sup> Staff Report at 6-17, 6-18.

<sup>74</sup> California's Electricity Options and Challenges: Report to the Governor, Executive Summary at 3-4 (Joint Report).

<sup>75</sup> As noted in [Order No. 2000](#), which expanded on our [Order No. 888](#) ISO principles and experience with ISOs, independence is the bedrock principle of RTO formation.

<sup>76</sup> [81 FERC at p. 61,552](#).

<sup>77</sup> This requirement is consistent with the recommendation in the Staff Report at 6-18.

<sup>78</sup> In this regard we note that none of the recent reports or analyses of the events of the summer cite to the current congestion management structure as contributing to the high prices.

<sup>79</sup> The Staff Report cites, for example, to increases in natural gas costs (\$2 per MMBtu to \$6 per MMBtu January 2000 to September 2000); increases in the price of NOx credits (\$5 per pound to over \$40 per pound January 2000 to September 2000); factors contributing to scarcity of power to meet demand such as lower than expected hydroelectric output and unplanned power plant outages; unusually high temperatures; tight reserve margins; increased demand for energy; reduced imports from outside California. See Staff Report at pp. 5-2 to 5-7.

<sup>80</sup> The Staff Report cites market design problems including lack of forward contracting, inadequate demand response; underscheduling; and use of a single-price auction to

[61,367]

previous monthly market power index was in June 1998, when prices were estimated to be 39.9% higher than they would have been under competitive conditions. Average prices in August were higher than in June. While costs such as gas and NOx emissions rose, the report states that the numbers suggest that market power may have been exercised in June. With respect to all of the references in this footnote, the standard used to evaluate market power was bids above short-run marginal cost.

[61,368]

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establish price. See Staff Report at 5-9 to 5-18. The report shows that design problems may have provided incentives for the exercise of market power. See Staff Report at 5-9 to 5-26. While findings of specific exercises of market power are not in the record, the Staff Report refers at p. 5-20 to the analysis of the Market Surveillance Committee (MSC) of the ISO, which estimated a significant degree of market power being exercised in California markets for the period October 1, 1999 to June 30, 2000. The MSC estimated prices for must-take energy over the entire period were 36.3% higher than they would have been under competitive conditions. For the last month of the sample, June 2000, they estimated that prices were 64.6% higher than they would have been under competitive conditions. The highest

<sup>81</sup> Staff Report at 5-19.

<sup>82</sup> Price movements in California Electricity Markets, Analysis of Price Activity: May-July 2000, California Power Exchange, p. 17 and 25. Cambridge Energy Research Associates (CERA) has concluded that a significant rise in spot prices can be expected when reserve margins decline below the 15 to 20 percent range. The Summer 2000 Spot Electricity Markets Outlook; Divergent Trends in Price Volatility, CERA, Lawrence J. Makovich and Joseph Sannicandro, July 2000.

<sup>83</sup> In order to encourage the expansion of Demand Response programs, we will not extend this market reform to bids for load response.

<sup>84</sup> For example, if the highest bid selected in the ISO real-time market is \$75/MWh, this will set the market clearing price and all sellers will receive \$75. This is the same pricing algorithm that is used now. However, if the highest bid selected is \$160/MWh and the second highest bid selected is \$75/MWh, the supplier bidding \$160 would be paid \$160/MWh for the amount it supplied, and the market clearing price for all other sellers would be set at \$75/MWh. In addition, as discussed below, the supplier receiving \$160/MWh would be required to report that bid to the Commission and provide certain cost information to the Commission.

[61,369]

[61,371]

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<sup>85</sup> This proposed market redesign will also apply to the ISO's Replacement Reserve Capacity Market with one modification. In certain instances, a supplier may potentially receive both a capacity and energy payment. Therefore, the capacity payment for replacement reserves will be contingent on whether the supplier is called on to produce energy. In that event, the supplier will receive only the energy payment.

<sup>86</sup> The IOUs have divested most of their fossil generation and, as a result, now own mostly hydro and nuclear generation with running costs of less than \$20/MWh. However, gas is the marginal fuel in California and, therefore, we expect to see bids above \$150 under some market conditions. We intend here to monitor these bids, not to prohibit them. We also fully appreciate that high cost suppliers will bid a margin above their variable costs as a needed contribution to their fixed costs. The Staff Report concludes that at times of peak demand running costs can be in the range of \$160 to \$200/MWh for some units. Staff Report at 3-21 and 5-3. In addition, the PX report (at page 30) on price activity May/July 2000 indicates that variable costs during peak periods can approach \$500/MWh for some units.

<sup>87</sup> Natural gas comprises about 55 percent of California's fuel mix.

<sup>88</sup> Staff Report at 3-21.

<sup>89</sup> Average California regional gas prices peaked at about \$6/MMBtu in September and are trending down toward \$5/MMBtu. Natural Gas Intelligence weekly Gas Price Index, Vol. 13, No. 24. NOx costs for the San Diego area have remained above \$40/lb. Cantor Fitzgerald Market Index, October 25, 2000.

<sup>90</sup> A combined-cycle generating unit with a heat rate of 10,000 Btu/KWh will incur fuel costs of \$50/MWh, and NOx emission costs of \$40/MWh. The remaining \$60/MWh will permit an investment payback of 5 years if the unit is selected for dispatch at the \$150 level about one-third of the time (*i.e.*, 8 hours per day). Selection for one-fourth of the hours would permit a ten year payback and selection for one-fifth of the hours would permit thirty (30) year payback.

<sup>91</sup> However, given the new and dynamic environment, the Commission is willing to explore any proposal for equitable relief, provided that it would ensure that California's electric markets remain capable of attracting investment while also mitigating the severe

[61,372]

[61,373]

[61,376]

No public utility shall, with respect to any transmission or sale subject to the jurisdiction of the Commission: (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage; or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect,

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financial consequences of last summer's high prices.

<sup>92</sup> [92 FERC at p. 61,606](#).

<sup>93</sup> We leave undisturbed the ISO's \$100 purchase price cap for Replacement Reserves during this time period.

<sup>94</sup> We note that one of the major costs of scarcity in California is the cost of NOx allowances which were trading in August for \$40/pound or approximately \$80,000/ton. By comparison, NOx allowances were trading in the Northeast for about \$400/ton.

<sup>95</sup> See Staff Report at 5-7, 5-8, *citing* California Energy Commission's reports on their website which has a listing of the proposed generation. The website is [www.energy.ca.gov/sitingcases/projects\\_since\\_1979.html](http://www.energy.ca.gov/sitingcases/projects_since_1979.html).

<sup>96</sup> The use of a "paper" hearing rather than a trial-type evidentiary hearing has been addressed in several cases. *See, e.g., Public Service Company of Indiana*, [49 FERC ¶61,346](#) (1989), *order on reh'g*, [50 FERC ¶61,186](#), *opinion issued*, Opinion 349, [51 FERC ¶61,367](#), *order on reh'g*, Opinion 349-A, [52 FERC ¶61,260](#), *clarified*, [53 FERC ¶61,131](#) (1990), *dismissed*, *Northern Indiana Public Service Company v. FERC*, 954 F.2d 736 (D.C. Cir. 1992). As the Commission noted in Opinion No. 349, [51 FERC at pp. 62,218](#) -19 & n.67, while the FPA and the case law require that the Commission provide the parties with a meaningful opportunity for a hearing, the Commission is required to reach decisions on the basis of an oral, trial-type evidentiary record only if the material facts in dispute cannot be resolved on the basis of the written record, *i.e.*, where the written submissions do not provide an adequate basis for resolving disputes about material facts.

<sup>97</sup> Section 205(b) provides that:

[61,377]

either as between localities or as between classes of service.

Section 205(c) provides the Commission discretion to prescribe rules and regulations, and to establish filing requirements “within such time and in such form as the Commission may designate.”

[61,378]

Sec. 213. (a) When complaint has been made to the Commission concerning any rate or charge for any service performed by any public utility, and the Commission has found after investigation that the public utility has charged an unreasonable, excessive, or discriminatory amount for such service in violation of any provision of this title, the Commission may order that the public utility make due reparation to the complainant thereunder, with interest from the date of collection. No such order shall be issued unless the complaint is filed with the Commission within two years from the date of the payment. (b) If the public utility does not comply with the order for the payment or reparation within the time specified within such order, action may be begun in any court of competent jurisdiction to recover the same within one year from the date of the order, and not thereafter.

[61,379]

[61,380]

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<sup>98</sup> 102 Stat. 2299 (1988). The RFA amendments to Section 206 are discussed *infra*.

<sup>99</sup> As discussed in Section C.2., *infra*, under the Commission’s and the courts’ interpretations of Section 206, there are limited circumstances in which the Commission can order refunds for past periods.

<sup>100</sup> Proposed Section 213 read as follows:

<sup>101</sup> *See, e.g., City of Bethany v. FERC*, 727 F.2d 1131 (D.C. Cir. 1984), *cert. denied*, 469 U.S. 917 (1984).

<sup>102</sup> The House passed H.R. 2858, a Senate Committee amended the House-passed bill, and the Senate passed H.R. 2858, as amended.

<sup>103</sup> S. Rep. No. 491, 100th Cong., 2d Sess. 3-4 (1988), *reprinted in* 1988 U.S.C.C.A.N. 2685.

<sup>104</sup> S. Rep. No. 491 at 5, *reprinted in* 1988 U.S.C.C.A.N. 2687.

[61,381]

purchasers of the [energy] had sufficient notice that the approved rate was subject to change”).

The goals of equity and unpredictability are not undermined when the Commission warns all parties involved that a change in rates is only tentative and might be disallowed. . . . As we stated in [*Public Service Co. of Colorado v. FERC*, 91 F.3d 1478 (D.C. Cir. 1996)], “[a]bsent detrimental and reasonable reliance, anything short of full retroactivity . . . allows [some parties] to keep some unlawful overcharges without any justification at all.” 91 F.3d at 1490.

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<sup>105</sup> S. Rep. No. 491 at 5-6, reprinted in 1988 U.S.C.C.A.N. 2687-88.

<sup>106</sup> *Towns of Concord, Norwood and Wellesley v. FERC*, 955 F.2d 67, 71-72 (D.C. Cir. 1992) (citations and footnotes omitted) (*Towns of Concord v. FERC*). See also *Natural Gas Clearinghouse v. FERC*, 965 F.2d 1066, 1075 (D.C. Cir. 1992).

<sup>107</sup> *Towns of Concord v. FERC*, 955 F.2d at 75. See also *Texas Eastern Transmission Corp. v. FERC*, 102 F.3d 174, 188-89 (D.C. Cir. 1996) (filed rate doctrine “seeks to prevent customers from relying on certain rates, only to find later that their purchasing decisions have been upset and their costs increased.”); *Public Utilities Comm’n of California v. FERC*, 988 F.2d 154, 164 (D.C. Cir. 1993) (“when determining whether a FERC order violates either the filed rate doctrine or the rule against retroactive ratemaking, this court inquires whether, as a practical matter, the

<sup>108</sup> The court determined that the Commission had committed legal error.

<sup>109</sup> [15 U.S.C. §717](#) (d) (1994). Section 5 of the Natural Gas Act is analogous to Section 206 of the FPA.

<sup>110</sup> In *Exxon Co., U.S.A. v. FERC*, 182 F.3d 30, 49 (D.C. Cir. 1999), the court held: