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ASLEEP AT THE SWITCH: FERC'S OVERSIGHT OF ENRON CORPORATION—VOL. III

HEARING

BEFORE THE

COMMITTEE ON
GOVERNMENTAL AFFAIRS
UNITED STATES SENATE

ONE HUNDRED SEVENTH CONGRESS

SECOND SESSION

NOVEMBER 12, 2002

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

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

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

Docket No. EL01-1-000

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

Docket No. EL01-2-000

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

Docket No. EL01-10-000

ORDER DIRECTING REMEDIES FOR CALIFORNIA
WHOLESALE ELECTRIC MARKETS

Issued: December 15, 2000

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

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

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

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

Docket No. EL01-2-000

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

Docket No. EL01-10-000

ORDER DIRECTING REMEDIES FOR CALIFORNIA WHOLESALE ELECTRIC MARKETS

(Issued December 15, 2000)

Introduction and Summary

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

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

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

The Commission herein adopts the following remedial measures:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Background

A. August 23 Order

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

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

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

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

B. Staff Report

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

C. November 1 Order

The Commission issued an order on November 1, 2000 proposing measures to remedy the problems identified in the Staff Report. [5] The Commission found that the "electric market structure and market rules for wholesale sales of electric energy in California were seriously flawed and that these structures and rules, in conjunction with an imbalance of supply and demand in California, have caused, and continue to have the potential to cause, unjust and unreasonable rates for short-term energy . . . under certain

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[2]Id. at 61,608.

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

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

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

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

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

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

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

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

[7] Id. at 61,350.

[8] Id.

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

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

D. Related Complaints and Other Filings

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

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

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

[9] 18 C.F.R. § 385.206 (2000).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Thirteen intervenors filed comments opposing CMUA's complaint, asserting that CMUA failed to adequately support its position on that matter, that cost-based rates would inhibit the formation of a competitive market within California, and that the complaint is premature in light of the consolidated hearing proceeding. Four intervenors filed comments supporting the complaint, contending, among other things, that cost-based rates are a superior alternative to price caps. PG&E and SoCal Edison each filed motions to intervene and comments arguing that the Commission should adopt the market mitigation

measures previously outlined in their Joint Motion for Emergency Relief. [16] One individual, Mr. Bruce W. Simonton, filed comments urging the Commission to consider the adverse impact that unregulated generation plant downtime will have on cost-based rate determinations.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

8. California Commission's Motion to Compel

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

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

(continued...)

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

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

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

9. California Governor's Comments

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

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

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

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

E. December Orders

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

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

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

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

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

Discussion

A. Procedural Matters

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

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

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

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

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

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

[28] 18 C.F.R. § 385.214 (2000).

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

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

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

B. Overview of Price Mitigation

1. The Fundamental Remedy

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

2. Summary of November 1 Order

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

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

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

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

3. Benefits of Self Scheduling

We reaffirm in this order the central piece of our proposed price mitigation, which is the elimination of the requirement for the IOUs to sell all of their generation into and buy all of their energy needs from the PX. This requirement caused the over reliance on spot markets, which lies at the very heart of the high prices in California. By eliminating this restriction, we will release the entirety of the IOUs' 40,000 MW of peak load from the PX. In every real sense, the IOUs will be free to mitigate their own spot price exposure by meeting their requirements (under long-term contracts in the bilateral markets). Just as significantly, the IOUs will be able to use the 25,000 MW of generation which they still

own or have under contract to serve their load without having to contract with anyone. [30] This places 25,000 MW of resources directly under the jurisdiction of the California Commission. Thus, the California Commission is free to price these MWs at cost or any way it sees fit for setting retail rates. IOUs will no longer be required to bid in their own resources and buy the energy back at the market clearing price. This is a comprehensive measure which will mitigate the spot market exposure of most of the peak load in California.

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

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

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

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

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

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4. Functioning Forward Markets Will Be There for California

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Removal of the mandatory buy/sell requirement and elimination of chronic underscheduling will directly limit the amount of load in the most volatile spot market – the real-time imbalance energy market. Just as importantly, we believe that this reform will allow the ISO to focus on the business of running the transmission system rather than a

marketplace. Even at peak times, only about 2,000 MW (i.e., about 5 percent of peak load) will now be in the real-time market, down two-thirds from the prior high of 6,000 MW. This will, therefore, substantially reduce the cost exposure to buyers who now can move 4,000 MW of load into the forward markets. We again emphasize that this form of price mitigation is very effective without introducing traditional cost-of-service pricing which reflects the cost of the assets without any regard to market conditions. Some form of administratively determined price would simply dampen the supply response in the long run.

6. Limitations on the Single Price Auction

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

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

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

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

7. Commitment to Ongoing Market Monitoring

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

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

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

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

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

8. There Are No Easy Answers

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

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

9. Justness and Reasonableness of Rates

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

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

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

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

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

We have been faced in this case with the difficult question of what makes a market-based rate unjust and unreasonable. There is no precise legal formulation for setting a just and reasonable rate and no precise bright line for when a rate becomes unjust and unreasonable. Under long-standing Supreme Court case law, rates must fall within a zone of reasonableness where the rates are neither so low as to be "less than compensatory" nor

so high as to be "excessive" to consumers.[43] While high prices in and of themselves do not make a rate unjust and unreasonable (because, for instance, underlying production prices may be high), if over time rates do not behave as expected in a competitive market, the Commission must step in to correct the situation.[44] Further, while exercises of market power may cause a rate to be unjust and unreasonable, in the circumstances here, independent of any conclusive showing of a specific abuse of market power, a variety of factors have converged to drastically skew wholesale prices under certain conditions: significant over-reliance on spot markets which by their very nature can produce dramatic price increases when supply is tight; significant increases in load combined with lack of new facilities as well as reduced availability of supply from out of state; chronic underscheduling; and lack of demand responsiveness to price. There is not sufficient evidence on this record to find that particular sellers have exercised market power or that they have violated Commission-approved market rules. Moreover, going forward, we have no assurance that rates will not be excessive relative to the benchmarks of producer costs or competitive market prices, due to the circumstances listed above. Therefore, we reaffirm our findings that unjust and unreasonable rates were charged and could continue to be charged unless remedies are implemented.

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

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

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

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

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

C. Requirement to Sell Into and Buy From the PX

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

1. Self Supplying IOU Load

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

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

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

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

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

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

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

2. California Commission Comments

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

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

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

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

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

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

D. Underscheduling of Load and Resources

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

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

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

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

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

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

1. The Proposed Five Percent Deadband

a. Comments

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

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

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

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

b. Commission Determination

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

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

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

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

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

2. Generation Penalty Proposals

a. Comments

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

b. Commission Determination

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

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

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

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

3. ISO Implementation

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

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

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

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

4. Conclusion

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

E. Level of Breakpoint

1. Background

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

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

2. Comments

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

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

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

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

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

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

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

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

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

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

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

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[62]DOE at 6-7.

[63]TURN/UCAN at 18.

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

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

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

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

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

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

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

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

[68]ISO comments at 11-13.

[69]PX comments at 45-47.

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

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

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

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[70]ISO comments at 12.

[71]FTC at 10.

[72]CMUA at 17-20

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

[74]Metropolitan at 13-15.

[75]SMUD at 15-25.

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

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

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

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[76]City of San Diego at 24.

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

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

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

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

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

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[79] Calpine at 14.

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

[81] PPL Parties at 36.

[82] EPSA at 15-20.

[83] Southern Parties at 49.

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

3. Commission Determination

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

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

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

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[84]Enron at 6-8.

[85]Duke Energy at 43-48.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

4. Refund Period

The November 1 Order proposed to condition market-based rates on sellers remaining subject to potential refund liability through December 31, 2002 (approximately 27 months) in order to ensure just and reasonable rates during the period it takes to effectuate longer term remedies in the markets. Commenters assert that this condition exceeds the Commission's authority under section 206, which permits refunds for a period

of 15 months after the refund effective date, and argue that by proposing this condition, the Commission attempts to do indirectly what it cannot do directly under the FPA. [89]

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

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

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

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

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

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

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

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

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

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

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

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

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

5. Transaction Reporting Requirements

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

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

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

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

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

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

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

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

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

In addition, the seller must provide:

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

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

F. Governance of the PX and ISO

1. Background

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

2. Comments

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

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

[99]Gov. Davis at 6.

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

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

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

3. Commission Determination

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

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

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

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

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

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

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

G. Other Factors Requiring Immediate Action

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

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

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

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

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

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

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[105]California Commission Exhibit at 17.

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

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

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

H. Interconnection Procedures

1. Background

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

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[107] 93 FERC at 61,359.

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

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

2. Comments

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

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

3. Commission Determination

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

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

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

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

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

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

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

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

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

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

I. Longer-Term Measures

1. Background

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

2. Comments

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

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

[116] See Oversight Board at 19.

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

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

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

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

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

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

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

3. Commission Determination

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

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

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

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

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

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

J. Other Matters

1. Qualifying Facility (QF) Issues

A. Increased Output from QF Facilities

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

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

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

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

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

B. PX based Pricing for QF Contracts

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

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

2. Requests for Regional Price Cap

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[124] 18 C.F.R. § 292.204(b) (2000).

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

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

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

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

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

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

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

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

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

K. Related Complaints and Other Filings

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

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

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

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

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

The Commission orders:

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

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

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

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

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

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

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

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

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

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

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

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

By the Commission. Chairman Hoecker concurred with a separate statement to be issued later.

(SEAL) Commissioners Massey and Hébert concurred with separate statements attached.

David P. Boergers,
Secretary.

Appendix A - Intervenors and Respondents

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

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

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

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

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

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

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

Intervenors and Respondents to Complaint in Docket No. EL01-1-000

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

Intervenors and Respondents to Complaint in Docket No. EL01-2-000

Bonneville Power Administration
California Department of Water Resources
California Independent System Operator Corporation
California Large Energy Consumers Association
California Manufacturers and Technology Association
California Power Exchange Corporation
Cities of Redding, Santa Clara, and Palo Alto, California, and the M-S-R Public Power Agency (jointly)
City and County of San Francisco, California
Cogeneration Association of California and the Energy Producers and Users Coalition (jointly)
Duke Energy North America LLC, Duke Energy Trading and Marketing, LLC, and Duke Energy Merchants, LLC (jointly)
Dynegy Power Marketing, Inc., El Secunda Power, LLC, Long Beach Generation LLC, Cabrillo Power I LLC, and Cabrillo Power II LLC (jointly)
Enron Power Marketing, Inc., and Enron Energy Services, Inc. (jointly)
Independent Energy Producers Association
Merrill Lynch Capital Services, Inc.
Modesto Irrigation District
Morgan Stanley Capital Group Inc.
New York Mercantile Exchange
Northern California Power Agency
Pacific Gas and Electric Company
Pinnacle West Companies
PPL Montana, LLC, and PPL EnergyPlus, LLC (jointly)
Public Utilities Commission of the State of California
Reliant Energy Power Generation, Inc., and Reliant Energy Services, Inc. (jointly)
Sacramento Municipal Utility District
Southern California Edison Company
Southern Energy California, L.L.C., Southern Energy Delta, L.L.C., and Southern Energy Potrero, L.L.C. (jointly)
Tractebel Power, Inc.
Transmission Agency of Northern California
Williams Energy Marketing & Trading Company

Intervenors and Respondents to Complaint in Docket No. EL01-10-000

Alcoa Inc., Atofina Chemicals, Inc., Goldendale Aluminum Company, Kaiser Aluminum & Chemical Corporation, Northwest Aluminum Company, and Reynolds Metal Company (jointly)
Avista Corporation and Avista Energy, Inc. (jointly)
California Independent System Operator Corporation

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

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

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Independent System Operator and the
California Power Exchange,
Respondents.

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

Docket No. EL01-2-000

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

Docket No. EL01-10-000

(Issued December 15, 2000)

MASSEY, Commissioner, concurring:

It is no secret that I have been deeply concerned about the apocalypse occurring in California power markets. Prices have not been just and reasonable, and market power has been exercised. Today's order re-emphasizes these critical findings. As a result, the transfer of wealth from purchasers of power to sellers has been absolutely staggering and completely defies the public interest. No legitimate public purpose has been furthered by this regrettable spectacle. The State's two largest utilities are virtually bankrupt because the billions in wholesale power purchase costs vastly exceed the amounts they have been

allowed by state policy to recover from their customers. This is, of course, a mixed blessing -- it bankrupts the utilities yet in the short term protects the bulk of the State's consumers from these astronomical prices. Yet it is not sustainable long term, and it serves no legitimate policy interest to bankrupt the utilities. It seems rather clear to me that some day soon a federal court, if asked, will declare that the utilities are entitled as a matter of federal preemption to recover these high wholesale costs from their customers. That's the way I read applicable precedent such as Nantahala, Narragansett, and Mississippi Power & Light.[1] And once these costs are passed through, of course the entire state, not just San Diego, will be in a perfectly legitimate and understandable uproar.

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

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

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

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

these 25,000 MW of assets. As our order points out, this is roughly 60% of the market at peak, and is probably 90% of the market off peak. Under today's order, the California Commission may require the utilities to offer these 25,000 MW at regulated cost of service rates. Inexplicably, the California Commission objects to this provision, yet consumers who have been concerned about over reliance on FERC regulated wholesale markets should know that today's order "defederalizes" no less than 60% of the California market on peak days. In other words, had today's order been in effect over the past summer, fully 60% of generation supply on the hottest day could have been sold at prices capped by the California Commission at regulated cost of service rates. This is a huge pro-consumer change that the California Commission must embrace.

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

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

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

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

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

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

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

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

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

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

Therefore , I concur with today's order.

William L. Massey
Commissioner

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company

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

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

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

(Issued December 13, 2000)

HEBERT, Commissioner, *concurring:*

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

For all of these reasons, I respectfully concur.

Curt L. Hébert, Jr.
Commissioner

Committee on Governmental Affairs
EXHIBIT #A-64

98 FERC ¶ 61,165
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
William L. Massey, Linda Breathitt,
And Nora Mead Brownell.

Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices

ORDER DIRECTING STAFF INVESTIGATION

(Issued February 13, 2002)

Under the Federal Power Act (FPA) and Natural Gas Act (NGA), the Commission has a statutory obligation to ensure that prices in jurisdictional wholesale energy markets are just and reasonable. Following Enron Corporation's declaration of Chapter 11 bankruptcy on December 2, 2001, allegations have been made that Enron Corporation, through its affiliates, used its market position to distort electric and natural gas markets in the West. The Commission therefore intends to gather information on whether any entity, including Enron Corporation (through any of its affiliates or subsidiaries), manipulated short-term prices for electric energy or natural gas in the West or otherwise exercised undue influence over wholesale electric prices in the West, since January 1, 2000, resulting in potentially unjust and unreasonable rates in long-term power sales contracts subsequently entered into by sellers in the West.

Accordingly, we direct Commission staff to undertake a fact-finding investigation into whether any entity, including Enron Corporation (through its affiliates or subsidiaries), manipulated short-term prices in electric energy or natural gas markets in the West or otherwise exercised undue influence over wholesale prices in the West, for the period January 1, 2000, forward. Staff will also look into other factors that may have influenced contract terms. In conducting this broad investigation, Commission staff may obtain information on any and all matters relevant to potential market manipulation in the West, including comparative information from other markets in the country. Staff should complete its investigation as soon as practicable in light of the complexity and breadth of the investigation. Among other things, the Commission may use the information developed by this fact-finding investigation to determine how to proceed on any existing or future FPA section 206 complaints involving long-term power sales contracts relevant

to the matters investigated, or any formal FPA section 206 or NGA section 5 proceedings initiated on our own motion.[1]

The Commission orders:

(A) Staff is directed to undertake a fact-finding investigation to determine whether any entity, including Enron Corporation (through any of its affiliates or subsidiaries), manipulated prices in the electric or natural gas markets in the West, as discussed in the body of this order. Staff will also look into other factors that may have influenced contract terms. Staff is directed to report its findings to the Commission as soon as practicable.

(B) For the purposes of this fact-finding investigation, the General Counsel or her designee is hereby empowered, with respect to any matters relevant to this investigation, to administer oaths and affirmations; subpoena witnesses; compel their attendance and testimony; take evidence, compel the filing of special reports and interrogatories; gather information; require the production of any books, papers, correspondence, memoranda, contracts, agreements, or other records; perform all other

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[1] A number of formal section 206 complaints are currently pending before the Commission concerning the justness and reasonableness of prices in long-term sales contracts in the West in Docket Nos. EL02-26-000, EL02-28-000, EL02-29-000, EL02-30-000, EL02-31-000, EL02-32-000, EL02-33-000, EL02-34-000, EL02-38-000, EL02-39-000, and EL02-43-000. The staff investigation initiated here is not an investigation under section 206 of the Federal Power Act but will help inform the Commission on whether and how to proceed with respect to existing or future section 206 proceedings involving long-term contracts in the West. Further, we clarify that this staff fact-finding investigation does not address and does not prejudge any arguments made in individual section 206 complaint proceedings that long-term contracts should be modified as a result of market flaws in California that may have caused prices in long-term contracts to be unjust and unreasonable. Those arguments will be addressed separately when the Commission acts on pending or future section 206 complaints or any section 206 proceedings it institutes on its own motion.

duties in connection with this investigation as prescribed by law; and designate other staff members of the Commission as officers of the Commission with all the powers enumerated in this order.

By the Commission.

(SEAL)

Magalie R. Salas,
Secretary.

FEDERAL ENERGY REGULATORY COMMISSION
OFFICE OF MARKETS, TARIFFS AND RATES
Washington, DC 20426

Dated: May 8, 2002

To: Sellers of Wholesale Electricity and/or Ancillary Services to the California Independent System Operator and/or the California Power Exchange During the Years 2000-2001 (Listed on Attachment A)

From: Donald J. Gelinas
Associate Director
Office of Markets, Tariffs and Rates

Re: Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, Docket No. PA02-2-000

Pursuant to the Commission's order issued February 13, 2002, in the above-referenced proceeding, you are hereby ordered to respond to the following data request, including requests for admissions with respect to certain trading strategies that your company may have engaged in. The data request is being issued to all sellers of wholesale electricity and/or ancillary services to the California Independent System Operator and/or the California Power Exchange during the period 2000-2001. The data request is being posted on the Commission's web page for Docket No. PA02-2-000 and, in addition, is being sent by certified mail to those representatives of the companies designated by the companies as contacts for sellers of market-based rates or as corporate officials.

Your company's response is to be signed under oath, in the form of an affidavit, by your company's president, chief executive officer, general counsel, or a corporate officer of comparable authority and responsibility, after the company, under the supervision and control of that individual, has diligently conducted a thorough investigation into the trading activities of the company's employees and agents, including those of its affiliates[1] and subsidiaries, in the U.S. portion of the Western Systems Coordinating Council

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[1]An "affiliate" is defined as stated in 18 C.F.R. § 161.2 (2001); *see* The Power Company of America, L.P., 79 FERC ¶ 61,067 at 61,325-12 (1997) (applying definition of "affiliate" in the Commission's Standards of Conduct for Interstate Pipelines with Marketing Affiliates to non-EWG public utilities).

(WSCC) during the years 2000 and 2001.[2] **Your response is due on or before May 22, 2002.**

Your company's failure to respond in a timely and complete fashion may result in enforcement action, including the issuance of an order directing a public utility to show cause why the Commission should not revoke the public utility's authority to sell wholesale electricity and/or ancillary services at market-based rates.

I. Requests for Admissions

For the purposes of the following requests for admissions, refer to the three Enron Corporation memoranda that are attachments to the follow-up data request to Enron dated May 6, 2002. That data request and the three memoranda are posted on the Commission's web page for Docket No. PA02-2-000.

The two Enron memoranda dated December 6, 2000, and December 8, 2000, describe in detail certain trading strategies engaged in during the years 2000 and 2001 by Enron traders and, allegedly, traders of other companies active in wholesale electricity and ancillary services markets in the West and particularly in California. According to the memoranda, these trading strategies generally fall into two categories.

The first is described as "**inc-ing load**" into the California Independent System Operator's (Cal ISO) real time market. Here, a company artificially increases load on a schedule it submits to the Cal ISO with a corresponding amount of generation. The company then dispatches the generation it scheduled, which is in excess of its actual load. This, in turn, results in the Cal ISO paying the company for the excess generation. Scheduling coordinators that serve load in California were able to use this trading strategy to include generation of other sellers (*e.g.*, Powerex and Puget Sound Energy).

The second is described as "**relieving congestion**" and involves a company first creating congestion in the California Power Exchange's (Cal PX) market, and then "relieving" such congestion in the real time market. This trading strategy is accomplished

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[2]At a minimum, the signatory to the affidavit must state that he or she certifies that the information and documents provided constitute a response that is true and accurate to the best of that individual's knowledge, information, and belief formed, after a thorough investigation was diligently conducted, under the supervision and control of that individual, into the trading activities of the company's employees and agents, including those of its affiliates and subsidiaries, in the U.S. portion of the WSCC during the years 2000 and 2001.

through such actions as reducing schedules or scheduling energy in the opposite direction of a constraint (counterflows), for which the Cal ISO will make payment to the company.

The December 6, 2000, and December 8, 2000, Enron memoranda then outline ten "representative trading strategies" that employ "**inc-ing load**" and "**relieving congestion.**"[3] The following requests for admissions describe certain activities, using the names applied to the "representative trading strategies" in the Enron memoranda. While you are to refer to the Enron memoranda, you must respond with respect to the description of each activity contained below and, as applicable, provide the specified details as to each activity.

A. 1. Admit or Deny: The company engaged in activity referred to in the Enron memoranda as "**Export of California Power**" during the period 2000-2001, in which the company buys energy at the Cal PX to export outside of California in order to take advantage of the price spread between California markets (which were capped) and uncapped markets outside California.

2. If you so admit, provide complete details as to all transactions your company engaged in as part of this activity, including the dates of all purchases and sales of energy and/or ancillary services, counter-parties to the transactions, prices and volumes, delivery points, and corresponding Cal ISO schedules. Also, provide all documents that refer or relate to the activity described immediately above.

B. 1. Admit or Deny: The company engaged in activity described in the Enron memoranda as "**Non-Firm Export**" during the period 2000-2001, in which the company gets a counterflow (scheduling energy in the opposite direction of a constraint) congestion payment from the Cal ISO by scheduling non-firm energy from a point in California to a control area outside of California, and cutting the non-firm energy after it receives such payment.

2. If you so admit, provide complete details as to all transactions that your company engaged in as part of this activity, including the dates of all transactions, congestion payments received, corresponding Cal ISO schedules, counter parties, and delivery points. Also, provide all documents that refer or relate to the activity described immediately above.

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[3]The two dated memoranda list as number two both the **Non-firm Export** and **Death Star** strategies; thus, there are in fact a total of ten strategies listed, not nine.

C. 1. Admit or Deny: The company engaged in activity described in the Enron memoranda as "**Death Star**" during the period 2000-2001, in which the company schedules energy in the opposite direction of congestion (counterflow), but no energy is actually put onto the grid or taken off of the grid. This allows the company to receive congestion payments from the Cal ISO.

2. If you so admit, provide complete details as to all transactions that your company engaged in as part of this activity, including the dates of all transactions, all transmission and energy schedules, the counter parties, all congestion payments received. Also, provide all documents that refer or relate to the activity described immediately above.

D. 1. Admit or Deny: The company engaged in activity described in the Enron memoranda as "**Load Shift**" during the period 2000-2001. This variant of "relieving congestion" involves submitting artificial schedules in order to receive inter-zonal congestion payments . The appearance of congestion is created by deliberately over-scheduling load in one zone (*e.g.,* NP-15), and under-scheduling load in another, connecting zone (*e.g.*, SP-15); and shifting load from a congested zone to the less congested zone, thereby earning congestion payments for reducing congestion.

2. If you so admit, provide complete details as to all transactions that your company engaged in as part of this activity, including the dates of all transactions, all schedules of load by zone, and congestion payments received. Also, provide all documents that refer or relate to the activity described immediately above

E. 1. Admit or Deny: The company engaged in activity described in the Enron memoranda as "**Get Shorty**" during the period 2000-2001, also known as "paper trading" of ancillary services in which it: (i) sells ancillary services in the Day-ahead market; and (ii) the next day, in the real-time market, the company "zeros out" the ancillary services by cancelling the commitment to sell and buying ancillary services in the real-time market to cover its position. The phrase "paper trading" is used because the seller does not actually have the ancillary services to sell.

2. If you so admit, provide complete details as to all transactions that your company engaged in as part of this trading strategy, including the dates of all transactions; prices and volumes for sales of ancillary services in the

Day-ahead market; the cancellation of such sales, prices and volumes for the purchase of ancillary services in the real-time market to cover the company's position; and corresponding schedules. Also, provide all documents that refer or relate to the activity described immediately above.

F. 1. Admit or Deny: The company engaged in activity described in the Enron memoranda as "**Wheel Out**" during the period 2000-2001. Knowing that an intertie is completely constrained (*i.e.*, its capacity is set at zero), or that a line is out of service, the company schedules a transmission flow over the facility. The company also knows that the schedule will be cut and it will receive a congestion payment without actually having to send energy over the facility.

2. If you so admit, provide complete details as to all transactions that your company engaged in as part of this activity, including the dates of all transactions, corresponding schedules, counter parties, and congestion payments received. Also, provide all documents that refer or relate to the activity described immediately above.

G. 1. Admit or Deny: The company engaged in activity described in the Enron memoranda as "**Fat Boy**" during the period 2000-2001 in which the company artificially increases load on the schedule it submits to the Cal ISO with a corresponding amount of generation. The company then dispatches the generation its schedules, which is in excess of its actual load. This results in the Cal ISO paying the company for the excess generation. Scheduling coordinators that serve load in California may be able to use this activity to includes the generation of other sellers.

2. If you so admit, provide complete details as to all transactions that your company engaged in as part of this activity, including the dates of all transactions, corresponding schedules, and payments from the Cal ISO for excess generation (including both price and volumes). Also, provide all documents that refer or relate to the activity described immediately above.

H. 1. Admit or Deny: The company engaged in activity described in the Enron memoranda as "**Ricochet**," also known as "megawatt laundering," during the period 2000-2001, in which the company: (i) buys energy from the Cal PX and exports to another entity, which charges a small fee; and (ii) the first company resells the energy back to the Cal ISO in the real-time market.

2. If you so admit, provide complete details as to all transactions that your company engaged in as part of this activity, including the dates for all transactions, names of counter parties and whether they were affiliates, the fees charged, prices and volumes for energy that was bought and then re-sold. Also, provide all documents that refer or relate to the activity described immediately above.

I. 1. Admit or Deny: The company engaged in activity described in the Enron memoranda as "**Selling Non-firm Energy as Firm Energy**" during the period 2000-2001, in which the company sells or resells what is actually non-firm energy to the Cal PX, but claims that it is "firm" energy. This allows the company to receive payment from the Cal ISO for ancillary services that it claims to be providing, but does not in fact provide.

2. If you so admit, provide complete details as to all transactions that your company engaged in as part of this activity, including the dates for all transactions, prices and volumes, and corresponding schedules. Also, provide all documents that refer or relate to the activity described immediately above.

J. 1. Admit or Deny: The company engaged in activity described in the Enron memoranda as "**Scheduling Energy to Collect Congestion Charge II**" during the period 2000-2001, in which the company: (i) schedules a counterflow even though it does not have any available generation; (ii) in real time, the Cal ISO charges the company for each MW that it was short; and (iii) the company collects a congestion payment associated with the counterflow scheduled. This activity is profitable whenever the congestion payment is greater than the charge associated with the energy that was not delivered.

2. If you so admit, provide complete details as to all transactions that your company engaged in as part of this activity, including the dates for all transactions, corresponding schedules, prices and volumes, and congestion payments received. Also, provide all documents that refer or relate to the activity described immediately above.

K. 1. Admit or Deny: The company engaged in any activity during the period 2000-2001 that is a variant of any of the above-described activities or that is a variant of, or uses the activities known as, "**inc-ing load**" or "**relieving congestion**," as described above.

2. If you so admit, provide a narrative description of each specific time in which the company engaged in such activity and provide complete details of those transactions, including the dates of the transactions, counter parties, prices and volumes bought or sold, corresponding schedules, and any congestion payments received. Also, provide all documents that refer to or relate to such activities.

II. Requests for Production of Documents

A. Provide copies of all communications or correspondence, including e-mail messages, instant messages, or telephone logs, between your company and any other company (including your affiliates or subsidiaries) with respect to all of the trading strategies discussed in the Enron memoranda (both the ten "representative trading strategies" as well as "**inc-ing load**" and "**relieving congestion**"). This request encompasses all transactions conducted as part of such trading strategies engaged in by your company and the other company in the U.S. portion of the WSCC during the period 2000-2001.

B. Provide copies of all material, including, but not limited to, opinion letters, memoranda, communications (including e-mails and telephone logs), or reports, that address or discuss your company's knowledge of, awareness of, understanding of, or employment or use of any of the trading strategies discussed in the Enron memoranda, or similar trading strategies, in the U.S. portion of the WSCC during the period 2000-2001. The scope of this request encompasses all material that address or discuss your company's knowledge or awareness of *other* companies' use of the trading strategies discussed in the Enron memoranda, or similar trading strategies, including, but not limited to: (i) offers by such other companies to join in transactions related to such trading strategies, regardless of whether such offers were declined or accepted; and (ii) possible responses by your companies to other companies' use of such trading strategies. To the extent that you wish to make a claim of privilege with respect to any responsive material, please provide an index of each of those materials, which includes the date of the each individual document, its title, its recipient(s) and its sender(s), a summary of the contents of the document, and the basis of the claim of privilege.

III. Requests for Other Information

A. On page 2 of the December 8, 2000, Enron memorandum, the authors allege that traders have learned to build in under-scheduling of energy into their models and forecasts. State whether your company built under-scheduling into any of its models or forecasts during the period 2000-2001, and provide a narrative

description of such activity. Provide copies of all such models or forecasts prepared by or relied on by your company during the period 2000-2001 that had under-scheduling built into them.

B. Refer to the discussion of the trading strategy described as "**Ricochet**" in the Enron memoranda. State whether your company purchased energy from, or sold energy to, any Enron company, including Portland General Electric Company, as part of a "**Ricochet**" (or megawatt laundering) transaction during the period 2000-2001. Provide complete details as to such transactions, including the dates of the transactions; the names, titles, and telephone numbers of the traders at your company who engaged in such transactions; the prices at which your company bought and sold such energy (on a per transaction basis); the volumes bought and sold (on a per transaction basis); delivery points; and all corresponding schedules.

Committee on Governmental Affairs
EXHIBIT #A-65

COPY OF TRANSCRIPT

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NEVADA POWER COMPANY AND
SIERRA PACIFIC POWER COMPANY,

Complainants,

vs. Docket Nos. EL02-26-000

DUKE ENERGY TRADING and MARKETING, EL02-28-000
L.L.C., ENRON POWER MARKETING, EL02-33-000
INC., EL PASO MERCHANT ENERGY, and EL02-38-000
AMERICAN ELECTRIC POWER SERVICES
CORP.,

Respondents.

NEVADA POWER COMPANY,
Complainant,

vs. Docket Nos. EL02-29-000

MORGAN STANLEY CAPITAL GROUP, EL02-30-000
CALPINE ENERGY SERVICES, EL02-31-000
RELIANT ENERGY SERVICES, EL02-32-000
MIRANT AMERICAS ENERGY MARKETING, EL02-34-000
L.P., BP ENERGY COMPANY EL02-39-000
BP ENERGY COMPANY, and
ALLEGHENY ENERGY SUPPLY COMPANY,
L.L.C.

Respondents.

COPY OF TRANSCRIPT

SOUTHERN CALIFORNIA WATER COMPANY,

Complainant,

vs. Docket No. EL02-43-000

MIRANT AMERICAS ENERGY MARKETING, L.P.,

Respondent.

PUBLIC UTILITY DISTRICT NO. 1 SNOHOMISH, COUNTY, WASHINGTON,

Complainant,

vs. Docket No. EL02-56-000

MORGAN STANLEY CAPITAL GROUP, INC.,

Respondent.

TELEPHONIC DEPOSITION OF CHRISTIAN GOOD YODER
Taken on behalf of the Intervenor City of Tacoma
June 18, 2002

-- -- --

BE IT REMEMBERED THAT, pursuant to 18 C.F.R. 385.409(2001), the deposition of Christian Good Yoder was taken before Gary W. Koch, a Certified Shorthand Reporter, and a Notary Public for the State of Oregon, on June 18, 2002, commencing at the hour of 1:04 p.m., the proceedings being reported at the Law Offices of Cable Huston, 1001 SW Fifth Avenue, Suite 2000, Portland, Oregon.

1 APPEARANCES

2 JACK A. GUGGENHEIM
3 Attorney at Law
4 SIDLEY AUSTIN BROWN & WOOD
5 1501 K Street, N.W.
6 Washington, D.C. 20007
7 (202) 736-8000
8 Appearing on behalf of the Complainants
9 Nevada Power Company and Sierra Pacific Power
10 Company
11
12 PHILIP L. CHABOT, JR.
13 Attorney at Law
14 MCGUIRE WOODS LLP
15 1050 Connecticut Avenue, N.W., Suite 1200
16 Washington, D.C. 20036-5317
17 (202) 857-1700
18 Appearing on behalf of the Intervenor City
19 of Tacoma
20
21 CHARLES A. MOORE
22 Attorney at Law
23 LEBOEF LAMB GREENE & MACRAE
24 1000 Louisiana, Suite 1400
25 Houston, Texas 77002

1 (713) 287-2086
2 Appearing on behalf of the Respondent Enron
3 Power Marketing, Inc.
4
5 BRIAN ZIMMET
6 Attorney at Law
7 VAN NESS FELDMAN
8 1050 Thomas Jefferson Street, N.W.
9 7th Floor
10 Washington, D.C. 20007
11 (202) 298-1800
12 Appearing on behalf of Avista Energy and
13 Sempra Energy Trading Corporation
14
15 ERICA MCFARQUHAR
16 Attorney at Law
17 LATHAM & WATKINS
18 555 11th Street, N.W.
19 Washington, D.C. 20004
20 (202) 637-2141
21 Appearing on behalf of the Respondent Mirant
22 Americas Energy Marketing, L.P.
23
24 JAMES W. MOELLER
25 Attorney at Law

1 BRUNENKANT & HASKELL LLP
2 805 15th Street, N.W., Suite 1101
3 Washington, D.C. 20006
4 (202) 408-0700
5 Appearing on behalf of the Respondent BP
6 Energy Company
7
8 BRUCE BARNARD
9 Attorney at Law
10 MORRISON & FOERSTER
11 2000 Pennsylvania Avenue, Suite 5500
12 Washington, D.C. 20006
13 (202) 778-1661
14 Appearing on behalf of the Respondent El
15 Paso Merchant Energy
16
17 ROBIN SHICHMAN
18 Attorney at Law
19 SULLIVAN & WORCESTER LLP
20 1 Post Office Square
21 Boston, Massachusetts 02109
22 (617) 338-2412
23 Appearing on behalf of the Complainant
24 Snohomish County
25

1 DANIEL A. CURTO
2 Attorney at Law
3 MCDERMOTT WILL & EMERY
4 28 State Street
5 Boston, Massachusetts
6 (617) 534-4000
7 Appearing on behalf of the Respondent Morgan
8 Stanley Capital Group
9 .
10 NATALIE TINGLE STEWART
11 Attorney at Law
12 888 First Street, N.E.
13 Washington, D.C. 20426
14 Appearing on behalf of the Federal Energy
15 Regulatory Commission
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1 PORTLAND, OREGON;
2 WEDNESDAY, JUNE 19, 2002
3 1:04 P.M.
4
5 MR. CHABOT: Philip Chabot,
6 McGuire Woods, Suite 1200, 1050 Connecticut
7 Avenue, Northwest, Washington, D.C. 20036, for
8 the Intervenor City of Tacoma, Washington.
9 Charlie, would you like to go
10 next?
11 MR. MOORE: Sure. This is
12 Charlie Moore, Charles A. Moore, of LeBoef Lamb
13 Greene & MacRae, 1000 Louisiana, Suite 1400,
14 Houston, Texas 77002; telephone number (713)
15 287-2086; appearing for Enron Power Marketing.
16 MR. BARNARD: This is Bruce
17 Barnard of Morrison and Foerster, 2000
18 Pennsylvania Avenue, Suite 5500, Washington, D.C.
19 20006; e-mail bbarnard at mofo.com; (202)
20 778-1661; appearing on behalf of El Paso Merchant
21 Energy.
22 MR. GUGGENHEIM: This is Jack
23 Achiezer Guggenheim, J-a-c-k, A-c-h-i-e-z-e-r,
24 G-u-g-g-e-n-h-e-i-m, at Sidley Austin Brown and
25 Wood LLP, 1501 K Street, Northwest, Washington

1 D.C. 20007; phone number is (202) 736-8000;
2 appearing on behalf of the plaintiffs NPC and
3 SPPC.
4 And I would like to request a
5 copy of the transcript when we're done.
6 MR. MOVICH: This is Philip
7 Movich with Energy and Resource Consulting Group,
8 LLC; address 8055 East Tufts, that's T-u-f-t-s,
9 Avenue, Suite 1250, Denver, Colorado 80237;
10 appearing on behalf of City of Tacoma.
11 MR. CHABOT: I should note that
12 that is not a legal appearance. Mr. Movich is
13 a consultant to the City.
14 MS. SHICHMAN: This is Robin
15 Shichman, S-h-i-c-h-m-a-n, with the law firm of
16 Sullivan and Worcester LLP, 1 Post Office Square,
17 Boston, Massachusetts 02109. My phone number is
18 (617) 338-2412. The fax number is (617) 338-2880.
19 I'm appearing on behalf of Snohomish County.
20 MR. CURTO: This is Daniel
21 Curto, C-u-r-t-o, of McDermott Will & Emery;
22 address is 28 State Street, Boston, Massachusetts
23 02109; phone number is (617) 535-4000.
24 My e-mail is bcurto, C-u-r-t-o,
25 at mwe.com.

1 I'm appearing on behalf of
2 Morgan Stanley Capital Group.
3 MS. STEWART: This is Natalie
4 Tingle Stewart from FERC; my address is 888
5 First Street, Northeast, Washington, D.C. 20426;
6 telephone number is (202) 208-0267.
7 MR. MOELLER: This is Jim
8 Moeller, M-o-e-l-l-e-r. I'm with the law firm
9 of Brunenkent & Haskell LLP. Our address is
10 805 15th Street, Northwest, Suite 1101,
11 Washington, D.C. 20006; phone number is (202)
12 408-0700; fax number is (202) 408-5959.
13 I'm participating on behalf of
14 BP Energy Company.
15 And we also would like to
16 receive a copy of the transcript of the
17 deposition.
18 MR. ZIMMET: This is Brian
19 Zimmet, last name is spelled Z-i-m-m-e-t, from
20 the law firm of Van Ness Feldman. Van Ness is
21 two words, V-a-n, N-e-s-s. The address is 1050
22 Thomas Jefferson Street, Northwest, 7th Floor,
23 Washington, D.C. 20007. The phone number is
24 (202) 298-1800.
25 I'm appearing today on behalf of

1 Avista Energy and Sempra Energy Trading
2 Corporation.
3 MR. CHABOT: Is there anyone
4 else who needs to enter an appearance?
5 MS. MCFARQUHAR: I do. This
6 is Erica McFarquhar, M-c-F-a-r-q-u-h-a-r, Latham &
7 Watkins, 555 11th Street, Northwest, Washington
8 D.C. 20004; phone number (202) 637-2141; fax
9 number (202) 637-2201.
10 I'm here on behalf of Mirant.
11 And I'd like to get a copy of
12 the transcript.
13 MR. ZIMMET: This is Brian
14 Zimmet from Van Ness Feldman. If I could get a
15 copy of the transcript as well.
16 MS. SHICHMAN: This is Robin
17 Shichman at Sullivan and Worcester. We'd also
18 like a copy of the transcript.
19 MR. CURTO: Dan Curto of
20 McDermott. The same, please.
21 MR. MOORE: Charlie Moore with
22 LeBoef. Same here; also including the exhibits.
23 Let me ask you, Phil, are you
24 going to use the same exhibits you used at
25 Sanders' deposition or not?

1 MR. CHABOT: With the exception
2 of the subpoena, which will obviously be witness
3 specific, that's correct.
4 MR. MOORE: Okay. Yeah. I'll
5 take them both, then.
6 MR. CHABOT: Is there anyone
7 else who has yet to enter an appearance?
8 MR. BARNARD: This is Bruce
9 Barnard. I've entered my appearance already.
10 But I would like a copy of the transcript as
11 well. Thank you.
12 MR. CHABOT: Any other
13 preliminaries before we swear in the witness?
14 I'll ask the reporter to swear
15 in the witness.
16
17 CHRISTIAN GOOD YODER,
18 having been first duly sworn, was examined and
19 testified as follows:
20 EXAMINATION
21 BY-MR.CHABOT:
22 Q. Would you please state your full name.
23 A. Christian Good Yoder.
24 Q. And your current residence address?
25 A. 33106 Northwest Reeder Road, Portland,

1 Oregon 97231.
2 Q. And what is your current business
3 address?
4 A. UBS Warburg Energy LLC, 121 -- that's
5 Three World Trade Center, 121 Southwest Salmon,
6 Portland, Oregon.
7 Q. Mr. Yoder, I'd like to show you a copy
8 of a subpoena duces tecum which was issued by
9 Administrative Law Judge Cintron in this
10 proceeding; and ask that this be marked as Yoder
11 deposition Exhibit Number 1.
12 (Whereupon, a subpoena duces
13 tecum was marked Exhibit-1 for identification.)
14 BY MR. CHABOT:
15 Q. Is it correct that you are here today
16 in answer to that subpoena?
17 A. Yes.
18 Q. Do you have any documents that you
19 brought with you in response to the subpoena?
20 A. No.
21 Q. Could you please give a brief
22 description of your professional experience since
23 graduating from college.
24 A. Well, I attended law school at the
25 University of Calgary Law School, graduating in

1983.

I then worked for four or five years at the law firm of Macleod Dixon in Calgary, Alberta; after which I took a job with Trans Canada Pipeline of Calgary's marketing affiliate Western Gas Marketing Limited, where I worked -- I began that job in '89, I believe; and in 1992 Western Gas Marketing opened an office in Houston, Texas. I was transferred down to Houston as their senior counsel in that gas marketing office, where I worked until '94, when I joined Enron.

I joined Enron, and initially in '94 my work included -- I lived in Houston but worked with the opening of their Calgary office and gas marketing, primarily gas marketing matters in Calgary.

And in '98, after the merger with Portland General, I moved to Portland, Oregon, where I've worked with Enron Power Marketing until it went bankrupt, and I took a job with UBS Warburg in February of this year.

MR. MOORE: Mr. Yoder, this is Charlie Moore. Could you bring the microphone a little bit closer to you? I'm having some

1 difficulty hearing you.
2 MR. CHABOT: We're going to do
3 the best we can. We're on a short cord here.
4 Is that any better?
5 MR. MOORE: Mr. Yoder, if you
6 could just say something, I can tell.
7 THE WITNESS: Can you hear me
8 any better now?
9 MR. MOORE: Yeah, a little bit.
10 MR. CHABOT: Let's go off the
11 record a second.
12 (Off the record)
13 MR. CHABOT: Okay. Back on
14 the record.
15 BY MR. CHABOT:
16 Q. Do you recall the date on which Enron
17 went bankrupt?
18 A. No, I don't.
19 Q. Okay. It was in the fall of 2001,
20 correct?
21 A. Yeah, yeah, it was -- I don't have the
22 exact date.
23 Q. And what was your position while you
24 were at EPMI?
25 A. I started out working in a group of

1 attorneys that were -- we worked in the area
2 called Origination, and it was to be
3 distinguished from trading. And there was a
4 broad division there in terms of the assignment
5 of attorneys.
6 Worked for a year in
7 Origination. Most of that work was development
8 related, and was supervised by senior attorneys
9 in Houston at that time.
10 And, so, and then in the
11 beginning of '99, sometime in there, I don't
12 know the exact date, I was asked to work on the
13 master trading agreements that back up the
14 trading dimension of EPMI here in Portland.
15 Q. Okay. Were you transferred to the
16 trading group as part of that, or did you stay
17 within the Origination section?
18 A. No, the legal department was organized
19 in such a way that Mark Haedicke, the managing
20 director, was putting together teams of attorneys
21 that worked together; and there was a power
22 trading team. I was the only member of that
23 power trading team in Portland, but there were
24 other members in Houston, and so he transferred
25 me and had me start working in that, in that

1 team.
2 Q. And was Mr. Haedicke your immediate
3 superior?
4 A. Yes, he was the -- I'd like to clarify
5 that point. He was responsible for all the
6 decisions, transferring me to Portland, my
7 salary, my bonus, all those kind of things.
8 But in the power trading team
9 that I worked in, there were a group of
10 attorneys, including a team leader, that I would
11 occasionally and frequently talk to.
12 Q. And who was that?
13 A. Elizabeth Sager, S-a-g-e-r.
14 Q. Okay. Who were the other members of
15 the team in Houston?
16 A. Well, I'm going to give you all the
17 names I can remember, but they changed, and I
18 can't guarantee that history would show these to
19 be absolutely accurate.
20 But the lawyers I remember
21 working with in Houston, Elizabeth Sager; David
22 Portz; Leslie Hansen; Harlan Murphy, is one of
23 those attorneys; Janet Moore is in that group,
24 for a while. Let's see.
25 They often changed and were

1 moved around, so those are the ones I remember
2 right now. It was a fluctuating group, but
3 those were members of the team.
4 Q. Okay. What, if any, relationship did
5 you have with Richard Sanders?
6 A. Richard Sanders was the litigation
7 manager for the legal department of Enron North
8 America. And Mark Haedicke's instructions to
9 those of us that worked on commercial
10 transactions was that at the slightest indication
11 of litigation risk we were to involve Richard in
12 the discussion. So he was there, and we were
13 to keep him in the loop.
14 Q. Okay. I take it, then, his involvement
15 was separate and apart from either the
16 Origination or the trading groups?
17 A. Right. He worked across Enron North
18 America covering all litigation risk -- that was
19 my understanding -- that came out of the
20 business, regardless of the little subgroups that
21 some of us might have been in.
22 Q. Okay. And did you have any people who
23 worked under your direct supervision?
24 A. No, nobody reported to me.
25 Q. Okay. Mr. Yoder, as you know, there's

1 a number of investigations that are ongoing in
2 connection with the activities of Enron in the
3 years 2000 -- well, 2001, and on either side of
4 that, actually, in connection with those
5 investigations. Have you given any other
6 depositions?
7 A. Yes, I have.
8 Q. Could you tell us before whom?
9 A. I don't know if the two Senate
10 committees are technically in your legal parlance
11 as litigators call depositions, but I appeared in
12 front of the two Senate committees.
13 Then -- that was the Senate
14 Energy Committee and the Senate Commerce;
15 subcommittees of those committees.
16 Then, the three western Attorney
17 Generals, Washington, Oregon, and California, had
18 a deposition here in Portland, and I testified
19 there for one day.
20 Q. Do you recall when that was?
21 A. I'm sorry, I don't have the exact date.
22 But it would have been about two or three weeks
23 ago.
24 Q. Okay.
25 A. And, then, there was also a day in

1 Washington where I testified before the CFTC and
2 FERC, a group -- joint group.
3 Q. And, for the record, the "CFTC" stands
4 for the Commodities Futures Trading Commission,
5 correct?
6 A. Yes, yes. That's all.
7 Q. Okay. Have you been interviewed by any
8 entities conducting investigations?
9 A. No.
10 Q. Are you today under the influence of any
11 substances that would affect the honesty of your
12 testimony?
13 A. No.
14 Q. I'd like to show you a document, that
15 we'll mark as your deposition Exhibit No. 2.
16 This is an electronic version of what I believe
17 to be the hearing that was conducted by the
18 Senate Commerce Committee. It does not contain
19 your prefiled -- or excuse me -- your prepared
20 written statements, but only the oral remarks at
21 that hearing.
22 A. Okay.
23 (Whereupon, a transcript of a
24 Senate Commerce Committee hearing was marked
25 Exhibit-2 for identification.)

1 BY MR. CHABOT:
2 Q. Is this the committee hearing, the
3 Senate committee hearing to which you referred
4 earlier?
5 A. Yes, it appeared to be, yes.
6 Q. And I won't ask you to do it now, but
7 I'd like to leave open for you the opportunity
8 to make any corrections that you might feel
9 necessary after having a chance to review the
10 remarks that are transcribed in your Exhibit 2.
11 A. Okay. Okay.
12 Q. Your Exhibit No. 2 makes reference to a
13 series of meetings that I believe began on
14 October 3rd of 2000. Is that correct?
15 A. If you're referring to the meetings when
16 Richard Sanders came to Portland and began
17 talking to the whole group about the response to
18 the California subpoena and the trading
19 strategies, that's correct.
20 Q. Okay. Is it fair, then, to conclude
21 that there were discussions with respect to the
22 issue that was addressed in the October 3rd
23 meeting prior to October 3rd?
24 A. Well, my -- there was a -- there was a
25 subpoena issued by the California Public

1 Utilities Commission at some date earlier than
2 October 3rd, and Mark Haedicke and Richard
3 Sanders were directing our response to that
4 subpoena.
5 I personally wasn't in any
6 meetings where that issue was discussed in
7 Portland with that team. But the reason Richard
8 came to Portland was to focus in more closely
9 on responding to what was perceived by upper
10 management as legal risks coming out of
11 California.
12 Q. Okay. Although you did not participate,
13 are you aware of any meetings having occurred
14 prior to the October 3rd meeting in connection
15 with the response to the CPUC subpoena?
16 A. I don't have clear memory of any
17 meetings, but my assumption was that there were
18 discussions and meetings among the management
19 team about it. That's just --
20 Q. Okay. And who would you include among
21 the management team?
22 A. Well, I'm thinking of Mark Haedicke and
23 Richard Sanders, the legal -- I'm talking legal
24 management at this point.
25 Q. Okay. Separate from meetings, do you

1 recall any other telephonic or other
2 communications?
3 A. No, no, I don't.
4 Q. Okay. Did you attend the meeting on
5 October 3rd?
6 A. Yes, I did, uh-huh.
7 Q. And, to the best of your recollection,
8 who else was in attendance?
9 A. It was a big group, and I'll do my
10 best to list the people that I recall being
11 there. Richard Sanders was there; Gary Fergus,
12 an attorney from Brobeck, was there. There
13 would have been Dan Watkiss, an attorney from
14 Bracewell Patterson, was there. Jim Steffes,
15 upper regulatory from Houston, I believe was
16 there. Mary Hain was there. Stephen Hall,
17 Stoel Rives, was there. And there were others.
18 I don't think I've filled the conference room
19 that was there. But I do remember Tim Belden
20 from our trading group being there. And another
21 trader named Mike Driscoll at one time was
22 there.
23 I -- I attended -- it lasted
24 all day, and I attended parts of the meeting.
25 I was in and out of the meeting, but I attended

1 good parts of it, and remember those people.
2 Q. Do you remember Mr. Adamson having been
3 there?
4 A. If that is an economist that Gary Fergus
5 brought with him, yes. I remember another --
6 there were other people there. I just don't
7 remember their names. And I don't remember
8 Adamson specifically.
9 Q. Okay. I understand. And if along the
10 way anything I ask you jogs your memory, feel
11 free to volunteer.
12 A. I will.
13 Q. Do you recall any other traders besides
14 Mr. Belden or Mr. Driscoll?
15 A. No, those are the two that I remember
16 specifically.
17 Q. And how would you define Mr. Belden's
18 responsibilities within Enron?
19 A. He was the managing director of West
20 trading, power trading.
21 Q. And Mr. Driscoll?
22 A. He was a power trader in Tim Belden's
23 group. I'm not sure exactly what his role was.
24 But he was a power trader in Tim Belden's group
25 on the West desk.

1 Q. Okay. Do you recall if there were any
2 other traders in attendance that day?
3 A. I can't remember specifically. There
4 probably were, but I don't remember specifically.
5 Q. Do you recall if Mike Day was there?
6 A. I don't recall, no.
7 Q. Michael Smith?
8 A. I don't remember Michael Smith. I'm not
9 sure I would know him if I saw him.
10 Q. Jeff Dasovich?
11 A. It wouldn't -- yeah, Jeff was
12 regulatory, and it wouldn't surprise me at all
13 if the record -- some other people would testify
14 that he was there. He was regulatory. I just
15 don't remember seeing him in the room myself.
16 Q. Okay. Paul Kaufman?
17 A. Paul was a Portland regulatory attorney,
18 but he didn't work on FERC matters, or these
19 matters. I don't remember seeing him in that
20 room. But, you know, he was in Portland; he
21 was there.
22 Q. Okay. Did anyone listen in by telephone
23 conference, or anything of that sort?
24 A. Not that I remember, no.
25 Q. Okay. Did you take notes of the

1 meeting?
2 A. No, I didn't.
3 Q. Do you recall anyone else who took
4 notes?
5 A. Well, I had asked -- the way I had
6 been working with Steve Hall, the attorney from
7 Stoel Rives, I had asked Steve to make sure
8 that he sat in the entire meeting and took
9 notes, and so I'm assuming he did. He had some
10 written record of that, that meeting.
11 Q. Do you have any recollection of anyone
12 else having taken notes?
13 A. Well, I -- I don't have specific
14 recollection. I'm sorry. But I'm sure some
15 people did. But I don't recall specifically who
16 they were.
17 Q. Do you recall ever having seen Mr.
18 Hall's notes?
19 A. No. No, I don't remember looking at
20 his notes.
21 Q. To the best of your recollection, I'd
22 appreciate it if you could relate in as much
23 detail as you can -- understanding time has
24 passed and we do have time constraints -- but
25 if you could generally convey what was said and

1 by whom at that October 3rd meeting.
2 A. Well, to the best of my recollection, it
3 went like this: There were serious legal things
4 coming out of California. We had had the
5 subpoena. I don't know when all of this
6 happened exactly. But there was the possibility
7 of the bankruptcy of the California PX; there
8 were the utilities in trouble; and our upper
9 legal management was trying to prepare a response
10 to the California subpoena and the emerging
11 crisis, which included class-action lawsuits, and
12 so forth.
13 And, so, my -- my perception of
14 the event was that -- although I was in my
15 normal work mode of negotiating master trading
16 agreements with counterparties, and trying to
17 build the contractural portfolio of the trading
18 operation -- that the litigation team had decided
19 to come to town and talk, you know, have a
20 meeting, to learn and explore and figure out how
21 to manage the growing legal risks that were
22 coming out of California.
23 And, so, Richard began the
24 meeting, and we then --
25 Q. Excuse me, Richard --

1 A. Richard Sanders was the internal team
2 leader that called the meeting and brought the
3 outside lawyers and others to the meeting.
4 And the subpoena -- my
5 recollection was that the subpoena asked us to
6 disclose lots of information about all of our
7 trading activities, and the lawyers weren't sure
8 just what those trading transactions were.
9 We normally didn't look at all
10 of that under the microscope, and so we weren't
11 sure what -- what kind of trades or what the
12 subpoena required us to do.
13 And it soon became apparent that
14 information about the trades was housed in
15 Enron's electronic -- there were a number of
16 systems that pieces of the information were put
17 into. The price and economics might go into
18 one system; the delivery point and the term
19 might go in another; and the scheduling
20 information could go somewhere else.
21 It was my impression that there
22 were difficulties in getting all of the trading
23 information organized in a way that you could
24 responsively disclose it to the CPUC and have it
25 there.

1 And, so, we asked -- that was
2 why Richard asked the traders, Tim Belden, the
3 leader, to come up and tell us about that.
4 It was "Electricity Trading
5 101," with lawyers who had never seen this stuff
6 before.
7 And, so, that was why -- that
8 was what was going on in that room that day.
9 And, so, Tim I recall being up
10 at the white board drawing pictures and
11 describing the ISO, and the grid, and the map
12 of California, and lawyers were asking what to
13 him were probably very basic, simple questions.
14 But we were trying to, you
15 know, get a handle on what were the trades that
16 they did typically, what markets were they in,
17 how did all this information get collected, how
18 could we report it, you know, under the
19 subpoena.
20 And, so, it was a dialogue
21 discussion all day long, questions and answers
22 between the legal team and the traders.
23 And that's generally what it
24 was.
25 Q. Going back for a moment, when you said

1 "Tim," you mean Mr. Belden?
2 A. Tim Belden, yes.
3 Q. Okay. You indicated that part of the
4 information conveyed was the various areas in
5 which information was housed. I assume they're
6 computer data bases or programs?
7 A. Right. Yeah.
8 Q. Do you recall any of the names of
9 those?
10 A. Well, Gary Fergus was given the job of
11 tracking that down, is my memory. And there
12 was a -- there was a system called -- I heard
13 names like Enpower, Oracle, and -- I can't
14 remember. There's one or two more that were
15 mentioned where, when the traders got on their
16 system and did a trade, they entered information
17 into these internal conduits for accounting and
18 scheduling and deal recording purposes.
19 Those are the only names I
20 remember right now, Enpower, E-n-p-o-w-e-r; and I
21 remember hearing the word "Oracle" used a lot,
22 which I don't know what it means.
23 Q. Okay. Do you recall if anybody was
24 given the responsibility to circulate minutes or
25 any report on the meeting afterwards?

1 A. No, I don't recall that.
2 Q. And do you recall having -- with the
3 exception of the memos prepared by Mr. Hall, do
4 you recall seeing any such --
5 A. No.
6 Q. -- memorialization?
7 A. No.
8 Q. With respect to these data programs, do
9 you recall what, if anything, was said about
10 their physical location?
11 A. No. They were there -- I mean, my
12 understanding was that those data input links
13 were in Portland but had connections to Houston
14 through our electronic system. That's the limit
15 of my understanding of them.
16 Q. Okay. What generally was the
17 relationship between the Portland trading desk
18 and the Houston office?
19 A. Well, I didn't attend any of their
20 business meetings or their -- my understanding,
21 as an attorney working on negotiating master
22 agreements and not really there in the middle of
23 their discussions with their upper management in
24 Houston -- I was never in any of those meetings
25 -- but my understanding was that the West power

1 desk was given the responsibility of trading
2 power in the western market, everything west of
3 the Rocky Mountains in the WSCC control area;
4 and that Tim Belden reported to higher up
5 commercial people in Houston; and that our
6 electronic systems and risk management information
7 flow was closely flowing back and forth to
8 Houston; but that he had quite a bit of
9 autonomy to trade and develop and to meet his
10 budget assignment numbers out here. He had a
11 lot of autonomy to do that. That was my general
12 impression.
13 Q. When you say the West power desk is
14 that the same thing as when I said the Portland
15 trading floor?
16 A. Yes. Yes, it is.
17 Q. And do you know to whom Mr. Belden
18 reported?
19 A. Well, two names that I've heard him say
20 -- and I don't know the times for sure -- but
21 one was John Lavorato, L-a-v-o-r, "o" or "a,"
22 t-o, I'm not sure which; and Greg Whalley.
23 Those are the two names that I remember hearing
24 him say were his bosses.
25 Q. And were both those gentlemen located in

1 Houston?
2 A. In Houston, yes.
3 Q. Where was the West power desk physically
4 located?
5 A. It was on the third floor -- or excuse
6 me -- on the -- it's in Three World Trade
7 Center, and you come in on the -- I think it's
8 the third floor -- yes, I believe it's the
9 third floor. The reason is, you come in on a
10 walkway and you go up one flight on the
11 elevator, but I think when you're on the walkway
12 you're already on the second floor. So I think
13 it's the third floor of the Third World Trade
14 Center building.
15 Q. And is that the same building in which
16 PGE is located?
17 A. PGE is on the other floors in that
18 building, yes.
19 Q. Okay.
20 A. And some other buildings. There's three
21 -- there are three buildings compromising World
22 Trade Center, and my limited understanding was
23 that PGE occupied One World Trade Center, and
24 Three World Trade Center, and I think number
25 Two, they may have had some offices there, but

1 it was used for conferencing and public events
2 more.
3 Q. Okay.
4 A. But PGE had the other floors in that
5 building where the Enron floor was in, above and
6 below.
7 MR. CHABOT: Okay. I'd like
8 to have marked as your deposition Exhibit 3 a
9 collection of papers which consists of documents;
10 those beginning with an AB prefix were released
11 by the Federal Regulatory Energy Commission;
12 those beginning with an AA prefix were released
13 by or were provided by the State of California,
14 and were attached to a document which they filed
15 in support of a motion to reopen the record in
16 the Puget proceeding.
17 I have a copy for you here.
18 THE WITNESS: Okay. So AA is
19 California --
20 BY MR. CHABOT:
21 Q. If you take a look at the tab, the AA
22 tab --
23 A. Right.
24 Q. -- you recall that the commission
25 several weeks ago, the Federal Energy Regulatory

1 Commission, several weeks ago issued -- made
2 public three memoranda?
3 A. AB. Okay. Yes. Oh, yes, uh-huh.
4 Q. Okay.
5 MR. MOORE: Phil, for the
6 record, is this Sanders' deposition Exhibit No.
7 3?
8 MR. CHABOT: That's correct.
9 MR. MOORE: Thank you.
10 BY MR. CHABOT:
11 Q. And, then, the documents ahead of the AB
12 designation, those would have an AA designation
13 --
14 A. Uh-huh.
15 Q. -- were made public by the State of
16 California?
17 A. Uh-huh.
18 Q. And I'd like you first to turn to "A"
19 -- let's go to the AB documents, AB, a series
20 of zeroes ending with a "1." And --
21 A. Okay.
22 Q. -- if you go through that document --
23 I'm sure you're familiar with it by now.
24 A. Yes, yes, I recognize this document.
25 Q. Starting at AB4, there's a series of

1 practices that are referred to. And let me ask
2 you, Do you recall hearing the term "Death Star"
3 on October 3rd?
4 A. Yes.
5 Q. Okay. And had you ever heard of that
6 term prior to October 3rd?
7 A. No.
8 Q. Do you recall hearing the term "Load
9 Shift" on October 3rd?
10 A. Yes.
11 Q. Do you recall having heard that term
12 prior to October 3rd?
13 A. No.
14 Q. Do you recall hearing the term "Get
15 Shorty" on October 3rd?
16 A. Yes.
17 Q. Do you have any recollection of having
18 heard that term prior to October 3rd?
19 A. No.
20 Q. Do you recall hearing the term "Wheel
21 Out" on October 3rd?
22 A. Yes.
23 Q. Do you recall having heard that prior to
24 October 3rd?
25 A. No.

1 Q. Do you recall having heard the term "Fat
2 Boy" on October 3rd?
3 A. Yes.
4 Q. Do you recall, in this context, having
5 heard the term "Fat Boy" in any other context?
6 A. No.
7 Q. Have you heard -- do you recall having
8 heard the term "Ricochet" on October 3rd?
9 A. Yes.
10 Q. And had you heard that term prior --
11 A. No.
12 Q. -- to October 3rd in this context?
13 Okay. Who was it that
14 discussed these terms at the October 3rd meeting?
15 A. Generally, it was Tim Belden who
16 outlined and described them on the white board
17 while attorneys asked questions.
18 And at some point, as I said
19 earlier, I recall a trader named Mike Driscoll
20 being asked to elaborate and draw some diagrams.
21 And I don't remember names and
22 faces other than that. But it wouldn't surprise
23 me if other traders had come in during the day
24 to do a supplemental kind of explanatory thing.
25 Q. Okay. What, if anything, was the

1 reaction -- or do you recall any of the
2 participants having a reaction during the October
3 3rd meeting to any of these marketing techniques?
4 A. Well, the reaction to the names was
5 strong and negative by the attorneys. We were
6 shocked, and we felt -- we felt embarrassed and
7 ashamed of the names. I mean, they were
8 shocking names, and we hadn't heard them. And
9 people were, you know, just saying, "Oh, man,
10 what is this"? You know, that kind of a
11 reaction.
12 And, so, after the feeling about
13 the names came out and we got over that, when
14 we started probing into, "Well, what were you
15 doing when you used these names? What was the
16 actual transaction"? It was -- there was
17 another reaction there, and it was a sense of
18 bewildering complexity to us. We weren't --
19 none of us had ever traded in the ISO markets,
20 and all these little markets, and things.
21 And, so, we would say, "Well"
22 -- you know, we would begin asking these
23 elemental questions about "What is this word."
24 There's just lots of technical
25 terminology in words, and we tried to start

1 breaking it down. And there was a feeling of
2 bewilderment and complexity.
3 So, shock and rage about the
4 names; complexity, bewilderment, as we got into
5 what they were doing.
6 So, those were the two reactions
7 that I think I had certainly. And --
8 Q. At the October 3rd meeting did Mr.
9 Belden say anything about whether other parties
10 participated in the same or similar forms of
11 transactions?
12 A. I don't have -- I don't -- I cannot
13 recall a sentence coming out of his mouth saying
14 something like that. But in these -- but I
15 have sort of a general -- I have a general
16 sense that, yes, others had done some things
17 from time to time. But if I -- so I have a
18 general feeling that he may have said something.
19 But if you say, "Okay, what did he say
20 specifically"? I can't give you the sense, you
21 know. So --
22 Q. But it's fair to say that you had a
23 general impression that comments were made that
24 at least some of these practices were engaged in
25 by other parties?

1 A. Yes, I had a general impression.
2 Q. And I specifically asked about Mr.
3 Belden initially. Would your answer be the same
4 with respect to anything Mr. Driscoll might have
5 said?
6 A. Well, I don't -- I think he was -- my
7 memory of him was he was perhaps being asked to
8 explain nuances of a particular detail, and so
9 he wouldn't have made a more general comment
10 that I can recall.
11 Q. Do you have any recollection whatsoever
12 of specific entities that might have been
13 mentioned in the context of this general
14 discussion?
15 A. Well, without -- without knowing --
16 without being able to say which strategies were
17 employed by which companies, what times and
18 everything, a name that I, you know, remember
19 being tossed around was Power X, the BC utility.
20 But I can't be specific and say that "they did
21 this strategy on such and such a date." But I
22 remember that name being associated perhaps with
23 some of this trading activity.
24 Q. Okay. Perhaps if you could take a look
25 at document AA, and then the last digit is 8.

1 A. Is it on page 8?
2 Q. Yeah. Look in this corner.
3 A. Oh, I see what you mean, yes.
4 Q. It's the Bates numbers on the bottom.
5 A. Yeah. Okay. I follow that. Yes, I
6 have that page open.
7 Q. About 85 percent of the way down that
8 page there's a reference to both Power X and
9 Williams. And I wonder if that refreshes your
10 recollection in any way about what was said
11 either with respect to Power X or Williams.
12 A. Well, now, these notes show that those
13 -- that the writer of these notes mentioned
14 their names. And I don't know what the writer
15 meant by writing them down. But the name
16 Williams doesn't surprise me, or -- I mean, it
17 was a big trading company in the market. And,
18 so, the fact that that name was written down in
19 that meeting, if that's what these notes are,
20 it's not -- you know, that doesn't surprise me,
21 no.
22 Q. Does this handwriting look familiar to
23 you at all?
24 A. Well, I've seen these notes in other
25 depositions, and I know that people are saying

1 that these are Mary Hain's notes. And I've --
2 if I were presented this handwriting just right
3 off the -- you know, for first-time impression
4 -- I don't know whose it is. I don't recognize
5 her handwriting.
6 But there seems to be a general
7 assumption. Everybody is saying these are Mary's
8 notes, and I've kind of fallen into the practice
9 of saying, "Oh, yeah, these are Mary's notes."
10 But I don't recognize it. I
11 never saw the notes before these depositions
12 started, and I don't -- I'm not familiar with
13 her handwriting.
14 Q. Okay. To the best of your recollection,
15 what was -- what, if any, consensus was reached
16 in the course of the October 3rd meeting?
17 A. Well, the consensus -- I don't remember
18 being there at the close of the meeting, but
19 the feeling I had as being an internal attorney
20 working on the edges of what Richard was doing,
21 was that the litigation team had gained valuable
22 -- a valuable new reality check of information,
23 and that the consensus was that they were going
24 to start even making more efforts to analyze and
25 understand these trading strategies that had been

1 introduced at that meeting.
2 And Gary Fergus -- I have a
3 strong memory that Richard wanted Gary Fergus to
4 bring in his economist, and people to help him,
5 and interview traders, study the situation, get
6 into the software dimensions, the whole thing.
7 And, so, the consensus legally
8 was more serious work needed; Fergus and Sanders
9 heading it up and doing it.
10 That was my feeling of
11 consensus.
12 Q. Okay.
13 A. That there could be concerns, and they
14 had to be studied further.
15 Q. Okay. What do you recall having been
16 done, then, in the days immediately following
17 October 3rd?
18 Actually, if it helps break it
19 down, I think you'll find the next meeting is
20 around November 4th.
21 A. Right, yeah.
22 Q. So, in that month period, if you could
23 kind of describe what occurred.
24 A. Well, before -- actually, I can break it
25 down.

1 In my memory the big breaking
2 point was that December meeting. But sometime
3 between October and November I remember being
4 aware that a lot of legal work was being done
5 by Gary Fergus, and he was -- again, I can't
6 give you the specific dates and times -- but I
7 remember seeing him in a conference room talking
8 to traders.
9 I can remember -- you know, I
10 just had the feeling that he was having
11 interviews with these traders, and going into
12 detail.
13 I remember the IT people having
14 -- seeing them having discussions with Gary.
15 I can remember getting
16 peripheral information that the whole system, the
17 whole operation, was being scrubbed down.
18 And, so, in Steve Hall, the
19 attorney from Stoel Rives, who was there and had
20 been brought in in September to look at
21 California issues broadly before we were aware of
22 this particular issue, he was talking to people
23 and participating more directly in those kind of
24 discussions than I was.
25 So, my -- I was trying to keep

1 my regular master contract negotiation thing
2 going, but was aware that attorneys were studying
3 the matter in more detail and depth.
4 And I would have discussions
5 daily discussions with Steve Hall. That was my
6 conduit into the process.
7 And, then, Richard came back up
8 for a meeting in November, and the discussions
9 continued.
10 Q. Do you recall any attorneys conducting
11 interviews besides Mr. Fergus and Mr. Hall?
12 A. No, I can't.
13 Q. Okay.
14 A. They were the two that I remember.
15 Q. Did you conduct any interviews?
16 A. No, no, I didn't.
17 Q. So, in the period -- and I understand
18 what you said earlier, you see it more ending
19 in the December time frame.
20 A. Uh-huh.
21 Q. But let's focus on the month from
22 October 3rd to November 4th.
23 A. Right.
24 Q. Is it fair to say that your further
25 involvement during this period related only to

1 discussions with Mr. Hall?
2 A. Yes, yes. We -- he was -- he had come
3 over from the law firm. He was -- although he
4 didn't report directly to me, obviously, he was
5 -- I was to give him guidance and kind of tell
6 him what to work on there in the Portland
7 office. And, so, we had constant discussions
8 about issues.
9 Q. Okay. And, again, I know it's difficult
10 to put them in a time frame and relate them
11 after the fact, but if you could, to the best
12 of your ability, just summarize the nature of
13 those discussions.
14 A. Well, as I said earlier, I had asked
15 him to make sure that he was at that meeting.
16 I said, "That's going to be an important
17 meeting; make sure you're there; take notes;
18 let's talk about it; let's work" -- you know --
19 I'm talking October now, the October meeting.
20 And, so, as the -- in the
21 aftermath of the meeting, that was one of his
22 assignments, among many, that he was to follow
23 up on. And my memory is that he -- he would
24 have a discussion with a trader, or with Gary
25 Fergus. And, then, from time to time he would

1 come to my office, and we would draw the
2 diagrams, and argue with ourselves, and try to
3 clarify and understand -- we were learning. It
4 was a sharp learning curve exposure for us.
5 And, so, my memory is many
6 times having Steve come in, and we would draw
7 strategies on the board, and argue about them,
8 and say, "Well, what about this?" Or, "Does
9 this make sense?" Or, "Go ask this," or -- you
10 know, we were trying to learn.
11 And, so -- as well as working
12 then -- and that was not our entire workload.
13 I would say it was a small part of a burgeoning
14 workload related to trading in the West. We
15 had a lot of other things going on. We weren't
16 focused exclusively on that.
17 Q. Okay.
18 A. And I can -- and I remember him telling
19 me that he had talked to Gary, and -- there was
20 some discussion going on between Steve and
21 Fergus; and, you know, there were meetings with
22 traders from time to time. And it was a
23 dynamic process.
24 Q. Did he ever indicate to you that he was
25 preparing a written summary of his investigations

1 or --
2 A. Well, yes, I knew -- I was responsible
3 for -- I don't know the exact time. My memory
4 would place it sometime in early November of
5 saying, "Steve, I think we ought to commit this
6 to a memo," you know. And not that he -- he
7 was -- he was trying to distill it down. We
8 had agreed that we would try to understand these
9 as best we could and write them down.
10 But Richard Sanders had not
11 asked us to write a memo. And it was my -- I
12 think history has to record truthfully that it
13 was me that said to Steve, "Let's get it
14 written. Come on, get it in writing. We have
15 to have a snapshot as clear as we can of this
16 complexity," you know. "It will help" -- "it
17 will help the litigation team prepare, and it
18 will help upper management in Houston understand
19 the situation."
20 So I knew he was writing a
21 memo; I wanted him to write it; and pushed him
22 to get it done in November in time for the
23 December meeting.
24 Q. Do you know if anyone else was aware
25 that he was writing a memo?

1 A. I don't know that Richard was aware. I
2 don't know that Mark Haedicke was aware. I'm
3 sure that his -- well, I shouldn't say that. I
4 don't have direct memory. But I'm assuming that
5 his superiors at Stoel Rives law firm knew he
6 was working perhaps on something. I don't know
7 for sure. And I don't know about Gary Fergus.
8 But that would have been the little ambit of
9 people that would have known.
10 Q. Okay. And is it fair to say that the
11 next event in the chronology was a meeting that
12 took place on or about November 4 and 5?
13 A. Yes. We had a monthly meeting, and
14 Richard came back up, and we met in November.
15 Q. Do you recall who attended that meeting?
16 A. No, I don't. I remember the December
17 one much better than the November one. I have
18 a memory, of course, of Richard being there. I
19 have a memory of Fergus being there. I have a
20 memory of traders coming in for more -- a
21 smaller group, focusing down more on information
22 systems and trading strategies more specifically.
23 But I don't -- it wasn't like the first
24 meeting. There wasn't a big cast of thousands;
25 and just a general 101 approach. That's my

1 memory of it.
2 Q. So is it fair to say that this was a
3 meeting that started honing in, I guess, on
4 these issues?
5 A. Yeah, yeah, it was a narrowing meeting.
6 But the December meeting was bigger again. It
7 got bigger, for reasons that I could explain.
8 Q. Okay. Why don't you take a look at
9 AA, the last two digits being 31.
10 A. Okay.
11 Q. And there's -- it is believed that these
12 are notes from that November 4-5 meeting, and I
13 just wondered if these notes refresh your
14 recollection in any way about --
15 A. Well, they appear to be -- I mean, this
16 was -- these appear to be notes about the same
17 points of discussion. And, so -- if people are
18 -- if someone is saying these are the November
19 meeting notes, I wouldn't deny that. I can't
20 say that, "Well, no, we didn't discuss that."
21 This seems to be about those topics.
22 Q. Uh-huh.
23 A. And, you know, you can see they're
24 talking about trades, and everything, and the
25 WSCC, you know. That was -- that seems -- that

1 was the flavor of the ongoing discussion. I
2 would agree with that.
3 Q. Okay. Did you attend -- the November
4 meetings went for two days; is that correct?
5 A. I don't remember if they went for two
6 days. But I remember being in and out of that
7 meeting too, and being aware that it was there,
8 yes.
9 Q. Okay.
10 A. Yes.
11 Q. And, then, what, if you know, was the
12 consensus coming out of those two days of
13 meetings?
14 A. I don't recall a different consensus
15 than -- I don't recall a difference in emphasis
16 or consensus. But it was more that we had a
17 -- I think the people that were experienced in
18 managing litigation were expecting lawsuits to
19 start coming.
20 In fact, I know in the December
21 meeting there were some class-action lawsuits had
22 been filed, and that's why a bigger team came
23 back to Portland then.
24 And, so, again, it was a
25 feeling of continued work: "We're not done with

1 this, guys; we have to keep looking at it and"
2 --
3 And also at that time -- and I
4 can't -- it's hard to pin down the dates of
5 exactly when, but my understanding was that the
6 litigation team had asked that the strategies be
7 stopped. That was a consensus, that I got the
8 feeling was done, that they asked Tim Belden to
9 stop the trading strategies. And some of them
10 had already stopped. And there's kind of a --
11 it's hard to pin down those dates.
12 But it was more serious study,
13 stop doing the strategies, let's continue to
14 comply, and figure out how we're going to get
15 all this information in some shape that we can
16 defend ourselves against expected lawsuits.
17 That was the consensus that I
18 felt.
19 Q. Do you recall the -- I'll call them
20 instructions to discontinue the trading
21 activities, do you recall seeing anything in
22 writing in that regard?
23 A. Not in writing, no, no.
24 Q. Do you recall seeing anything that
25 confirmed in writing that all or any one of the

1 practices had in fact been terminated?
2 A. Not in writing, no, no.
3 Q. Okay. Okay. So, did your role change
4 at all between November 4 and the December
5 meeting to which you've referred?
6 A. No, not really. I was doing the same
7 general work.
8 Q. Okay. And having the same periodic
9 conversations with Mr. Hall?
10 A. Yes, uh-huh.
11 Q. Okay. Any other conversations that you
12 recall or meetings that you recall?
13 A. The same as happened in October, we
14 would have periodic discussions. And he was
15 continuing to work. And my memory is sometime in
16 early November I said, "Now let's finish the
17 memo. Let's get it written."
18 And there were other priorities.
19 And I tried to keep that one on the table.
20 Q. Okay. And, then, I guess that does
21 bring us to the December 7th --
22 A. Right.
23 Q. -- meeting --
24 A. Yeah.
25 Q. -- correct?

1 A. Yeah.
2 Q. And do you recall who attended that?
3 A. Well, to me, my memory, that was a
4 bigger, more significant meeting than November.
5 Because my memory is that that was when the
6 outside counsel that was responding to the
7 class-action lawsuits were there.
8 And I remember Robin Gibbs from
9 Houston, who is a well known big litigator from
10 Houston was there; and there was an attorney
11 from California, from San Diego. And I don't
12 remember his name now. But he was -- we were
13 told that he was going to represent Enron in
14 the class-action lawsuits in California.
15 And, so, the tenor of that
16 meeting, or the tone of that meeting, was that,
17 you know, even more -- from my little trading
18 attorney prospective, there were even bigger and
19 more important outside litigators in that room
20 talking, and they were going back over -- they
21 had to go back over "Power Trading 101" and get
22 over the shock of the names again.
23 And that was what I thought
24 would be a helpful purpose of the memo, which
25 we then -- we distributed at that time. It was

1 to brand new, seasoned, veteran litigators, but
2 having no knowledge of the power trading business
3 before, had to come up to speed. And my
4 thought -- I was trying to help them by saying,
5 "Well, here's a little snapshot of what we've
6 learned in the last two months; see if this
7 helps you organize your approach."
8 Q. Okay.
9 A. And that was the way I saw myself
10 contributing to the work of the attorneys in the
11 area.
12 Q. Okay. So let's turn to the memo, then,
13 the December 6, 2000 memo. It appears at AB1.
14 A. Yes, I have it here.
15 Q. Okay. When did you first see the memo
16 in roughly this form?
17 A. My memory is I saw it about the time
18 that we distributed it, in early December.
19 Q. Okay. Did Mr. Hall give you a draft
20 initially that you reviewed, or did you see it
21 in pretty much the final form?
22 A. My memory is that I saw it looking kind
23 of like this. And, you know, in another -- in
24 another deposition there were -- there were --
25 there was shown to me a draft. It was in mid

1 November sometime. It wasn't addressed to me or
2 given to me on the face of it. And I didn't
3 recall seeing the draft. But my memory is that
4 I saw this in late November, early December.
5 But I'm not -- I'm not sure that there weren't
6 perhaps some other written versions of it out
7 there. I couldn't be for sure.
8 Q. And I just noticed, I had started asking
9 you before on page -- with respect to the
10 trading practices that begin on page 4, but I
11 also see the inc-ing, i-n-c-i-n-g --
12 A. Inc-ing and decking.
13 Q. And those are referred to in the
14 preceding pages. So let me ask you the same
15 question I did with respect to the other
16 practices. Had you ever heard of these
17 practices before the October 3rd meeting?
18 A. No. This was where I learned the names
19 and got familiar with them, yeah.
20 Q. Okay. Do you believe -- there's two --
21 there's a December 6th version of this
22 memorandum, then there's a December 8th version.
23 They appear to be essentially identical.
24 A. I think they are identical. And I
25 don't know of any differences in them.

1 Q. Do you know how they came to bear two
2 different dates?
3 A. No, I don't. I think Steve will
4 explain that. I'm not sure how that happened.
5 Q. Okay. From your perspective, did this
6 memorandum accurately describe all of the
7 practices that had been under discussion since
8 October 3rd?
9 A. Well, yes. I'd like to qualify that
10 "yes."
11 These were the practices that I
12 remember, so it covered all of them that I
13 remember talking about.
14 Now, the word "accurately," it
15 was as accurate a snapshot as we could get of a
16 very complicated situation.
17 And, so, would subsequent work
18 by others have the effect of showing that we
19 may have gotten something wrong in here? I
20 wouldn't be surprised. It wasn't written as a
21 final legal opinion. But it was as accurate as
22 we could get to meet that December deadline to
23 help the discussion process move along.
24 Q. What is the December deadline?
25 A. Well, the big outside counsel

1 class-action litigators needing to suddenly
2 understand what's going on in California.
3 Q. Do you recall if anyone in the trading
4 staff was asked to prepare any documentation as
5 part of the preparation of this December 6th
6 memo?
7 A. No, I -- the one fragment of memory I
8 have is that -- I know Steve would talk to
9 traders from time to time.
10 Q. Mr. Hall?
11 A. Stephen Hall, Mr. Hall would talk to
12 traders and ask for their -- to clarify his
13 understanding from time to time. And I have a
14 memory of Steve -- Steve telling me that he had
15 -- he had given this -- he had given this memo
16 to Tim Belden to review for accuracy, but that
17 Richard had wanted to bring it back. Richard
18 didn't want Tim to read the memo.
19 Q. Mr. Sanders?
20 A. Mr. Sander's, for whatever -- for some
21 -- I'm sure there was a good reason. So I
22 don't think the memo was reviewed by traders for
23 accuracy before we gave it to the team.
24 Q. Okay. And you're not aware of any
25 written materials that the traders provided?

1 A. No, I'm not. They certainly weren't
2 provided to me, if there were any.
3 Q. Do you know whether in the period after
4 November 4 anyone conducted interviews of the
5 traders besides Mr. Fergus and Mr. Hall?
6 A. I'm not aware of any other interviews
7 being conducted.
8 Q. Okay. Now, when I asked you earlier
9 about the involvement of or the participation of
10 other entities in practices the same or similar
11 to those described here, you did mention Power
12 X, as I recall.
13 A. Uh-huh.
14 Q. If you turn to page 2 of the December
15 6th memo, which is at AB2 --
16 A. Uh-huh.
17 Q. -- there's a reference, for example,
18 Power X appears again in the last full
19 paragraph.
20 A. Yes.
21 Q. As well as Puget Sound Energy.
22 A. Yes.
23 Q. And with respect to those two entities
24 in particular, do you recall in the period after
25 November 4 anything more specific with respect to

1 the activities of either Power X or Puget Sound?
2 A. No, nothing -- nothing specific or more
3 specific. I would have -- Steve wrote this
4 memo, and I would have seen those names and
5 just thought, "Oh, well, he learned something
6 from the traders and put the names in." And I
7 have no reason to question it, you know, that
8 it's there.
9 Q. Okay. And on page 3 of this memo, AB3
10 --
11 A. Uh-huh -- or, yes.
12 Q. -- in the paragraph under the subheading
13 "B," Representative Trading Strategies, there's a
14 reference there -- well, actually, the sentence
15 reads, "Enron's traders have used these nicknames
16 with traders from other companies to identify
17 these strategies."
18 Do you know what other companies
19 are there referred to?
20 A. No, I'm sorry, I can't give names for
21 that. I'm sorry.
22 Q. Do you have any understanding from that
23 sentence, or from the discussions that you had
24 with Mr. Hall or others, that these Death Star
25 references, Fat Boy references, and stuff, had

1 become common parlance among not only within
2 Enron but with other utilities?
3 A. Again, my general understanding, I
4 wouldn't -- when Steve wrote this in the memo,
5 that other entities were using these strategies,
6 that would not have surprised or shocked or
7 caused me to say, "Well, now, wait a minute.
8 Why is that sentence in there"? I would have
9 accepted the sentence because -- I -- just from
10 general discussions, it was my general
11 understanding that, yes, there were other
12 entities using similar strategies. They weren't
13 isolated and only at Enron.
14 But the follow-up question,
15 "Well, who, when, where?" I just -- I can't go
16 there. I had general knowledge that, yes, there
17 were wider practices, but I can't be more
18 specific than that.
19 Q. Similarly, in that same general context,
20 would you be surprised if traders outside of
21 Enron, if you used the term "Fat Boy," would
22 know what you were talking about?
23 A. I wouldn't be surprised. I wouldn't be
24 surprised.
25 Q. Okay. And on page 7, AB7.

1 A. Yes.
2 Q. That page contains a reference first at
3 8B to, quote, "Everybody does this, especially
4 for imports from the Pacific Northwest into
5 California."
6 Again, does that jog your
7 recollection at all as to what entities were
8 referred to?
9 A. I don't -- you know, I would assume
10 that -- I don't remember specific lists, but,
11 you know, there were a number of Northwest
12 entities that traded, and I'm just assuming they
13 would be in there.
14 Q. Was it also your understanding that some
15 of these practices in which Enron itself engaged
16 required the use of the -- required the use of
17 the physical assets of other utilities or
18 generators?
19 A. This is a question that I'm going to
20 have to ask you to repeat, because I'm not sure
21 I understand it.
22 Q. Okay. You've testified that you had a
23 general impression that other entities engaged in
24 similar practices.
25 A. Yes.

1 Q. You don't recall which entities.
2 A. Right.
3 Q. You don't recall what practices, but the
4 general feeling.
5 A. Yes.
6 Q. Did you have a similar feeling that even
7 as Enron alone engaged in these practices --
8 well, let me strike -- not as Enron alone --
9 but Enron, to carry out some of these practices,
10 required the assistance or cooperation, knowing
11 or otherwise, of other generators, transmitters,
12 and marketers?
13 A. Well, I had the -- I didn't have any
14 specific -- I don't have any specific
15 understanding of cooperative -- it's a hard
16 question for me to answer, because I -- you
17 know, we -- I know that we were -- Enron Power
18 Marketing was the classic middleman.
19 We didn't have any generators,
20 and we didn't have any -- we didn't have any
21 load for Enron Power Marketing itself. So we
22 were always on two sides of a transaction, just
23 generally speaking. That was our place in the
24 marketing.
25 And, so, in that most general

1 sense we wouldn't have been able to get any
2 energy or move any energy in any markets without
3 cooperating with other parties in these daisy
4 chains of transactions. And, so, we were always
5 linked up that way.
6 Now, if -- but I can't become
7 more specific than that and say, "Well, now,
8 with this company we used this generator to do
9 this strategy." I have no knowledge of that
10 specific area. I can't go further than that.
11 Q. Okay. So, I'm just going to throw out
12 some names now and see if it just jogs anything
13 with you.
14 Do you recall anything with
15 respect to the Northern California Power Agency,
16 for example?
17 A. NPCA?
18 Q. NCPA.
19 A. NCPA. My understanding is that we
20 traded with NCPA. I have memory -- in fact, we
21 didn't have as good a contract as we wanted to
22 have, and occasionally there would be pressure on
23 me to get a better contract with NCPA. But I
24 don't remember transactions. I don't remember
25 the specifics. I thought we were selling them

1 power, or buying wholesale power from them.
2 That was my understanding.
3 Q. Okay. Following up, then, what you said
4 earlier, is it fair to say that to the extent
5 that any -- that one of these strategies
6 required generation, Enron would have to rely on
7 the participation of some other entity?
8 A. Yes.
9 Q. To the extent that it relied upon
10 transmission, Enron would have to rely upon the
11 participation of some other entity?
12 A. Yes.
13 Q. And the same would be true with respect
14 to interconnection agreements?
15 A. Yes, yes, there would have been the need
16 for that, yes.
17 Q. Okay. And based upon your participation
18 in these discussions from October 3rd forward, do
19 you have any understanding as to what evidence
20 would exist to document those transactions?
21 A. Well, my -- my understanding of the
22 documentation of the trading strategies would be
23 as follows: They were -- they were all --
24 unlike our major business, which was trading
25 power, wholesale power, bilaterally under master

1 trading agreements at liquid delivery points,
2 this group of transactions, which I also always
3 understood, formed a very small part of our
4 overall portfolio, took place on the ISO in
5 their day-ahead or realtime markets and ancillary
6 services. There were three or four or five
7 little pricing point markets in the ISO, very
8 short term, all governed by the nonnegotiable
9 FERC-approved tariff.
10 And, so, it wasn't our big
11 long-term, you know, five-year contracts that
12 were being affected in this trading strategy
13 world.
14 And, so, my understanding was
15 always that the record of those transactions
16 would be in two places: One, it would be with
17 the ISO, because it had to happen on their
18 system in their software. All of them are
19 there somewhere, was my crude assumption.
20 And, then, Enron had its own
21 settlement group that did nothing but settle with
22 the ISO on all of our ISO transactions, and my
23 assumption was it would be in there, in that
24 software.
25 And we were ordered early on by

1 Richard to save everything and not destroy.
2 So, somewhere in Enron's
3 internal software, and the ISO, everyone of those
4 ISO strategies should be recorded. That was
5 always my understanding.
6 Q. And do you know whether that data has
7 been turned over by Enron at least to any
8 regulatory agency?
9 A. I don't know for sure, but I think it
10 has. I can remember Richard saying -- Richard
11 Sanders saying at some point that a lot of
12 transaction data was turned over to California.
13 Q. Okay.
14 A. I think. But don't -- you know, that's
15 my recollection.
16 Q. Okay.
17 A. Yeah.
18 Q. I don't want to take you beyond what
19 you recall.
20 It would be true also that
21 Enron's data would record transactions not just
22 for California but for the WSCC as a whole?
23 A. Oh, yeah, for the entire West, yes.
24 Q. Now, while this was going on, I
25 understand that you were still doing your day

1 job of doing the Enron contracts, correct?
2 A. Yes.
3 Q. And were these -- which contracts did
4 you have responsibility for?
5 A. Well, we used a master trading agreement
6 that we had. I guess to answer that, which
7 contracts did I have responsibility for, an
8 ever-changing group of counterparties that was
9 driven a lot by new, large-exposure commercial
10 deals. That's what I would tend to focus on.
11 There was always a need to
12 upgrade the contract portfolio. But if a
13 particular counterparty was having an RFP for a
14 major sale, or purchase, or something, then the
15 contract would have to be negotiated, and I
16 would be drug in.
17 So, at any one time there might
18 have been 30 or 40 master contract negotiations,
19 and I was involved in in different ways.
20 Q. Okay. And these were wholesale
21 contracts?
22 A. Wholesale, yes, wholesale; typically,
23 longer term; typically, liquid delivery point
24 transactions.
25 Q. And what was your experience with

1 respect to the number of such transactions in
2 the period September of 2000 through May of 2001
3 as opposed to the preceding months?
4 A. I don't -- I don't remember specifics.
5 But it was a busy time. There were -- I was a
6 busy guy back in that office negotiating during
7 that time.
8 Q. Okay.
9 A. And I -- the memory is blurred by the
10 passage of time, and the bankruptcy and
11 everything. But I remember that year being a
12 very, very busy year for me.
13 And, of course, there were other
14 attorneys in the power group in Houston that
15 helped out on -- I wasn't just handling it all
16 myself. There were other attorneys in the group
17 that worked on these big wholesale contracts from
18 time to time.
19 Q. Right. What I'm trying to get a sense
20 of is, Were there more of these contracts being
21 negotiated than had been the case in the period
22 prior to September of 2000?
23 A. It's hard for me to say much about
24 that. It seemed like I was always really busy
25 at Enron. I just don't --

1 Q. Okay.
2 A. I mean, it's hard to make a general
3 comment on that. I can't.
4 Q. But, again, these were long-term
5 contracts primarily?
6 A. Yes, yes. That's why they wanted an
7 attorney on them. Because they were not just a
8 day-by-day transaction. They might be five
9 years; they might be three years. And there
10 were big dollars at risk in those kind of
11 trades. And, so, they -- they wanted to make
12 sure we had the right contractural paper in
13 place.
14 Q. And were these for the -- throughout the
15 WSCC?
16 A. Yes. Counterparties west of the Rocky
17 Mountains in all regions.
18 Q. Okay. Just briefly, there's a -- it
19 comes out looking like a third memo, but since
20 the first two are alike --
21 A. Uh-huh.
22 Q. The memo -- in fact, I don't think it
23 has a date. It has a Bate stamp of 7 --
24 excuse me -- 17, AB17. And it's on the Brobeck
25 stationary?

1 A. Yes.
2 Q. How -- do you know how Enron got from
3 the December 6th and 8th memos to this undated
4 memo from Gary Fergus? I mean, can you
5 describe the process that you went through to
6 get through this?
7 A. You know, I can't really help you a lot
8 with that. I didn't see this memorandum until
9 the Senate -- I didn't see the Brobeck paper
10 until the Senate hearing. And, so -- and I
11 wasn't part of the discussion leading up to its
12 preparation.
13 Q. Okay.
14 A. So I don't know how it came about.
15 Q. Fair enough. Do you have any knowledge
16 about a transaction referred to as Silver Peak?
17 A. Yes.
18 Q. And what, to your best recollection, is
19 Silver Peak?
20 A. Well, to me that means a -- it was a
21 scheduling issue that Enron had had with the
22 California Power Exchange, PX, earlier, before
23 any of this -- later in the -- I don't remember
24 the exact dates. My memory is March, April,
25 earlier in the year.

1 It would have been an issue
2 that a trading practice of scheduling at an
3 export point was challenged by the PX, and we
4 had to -- Richard Sanders got involved, and
5 there were meetings held with the PX, and it
6 settled. That's my memory of it.
7 Q. Okay. Do you recall any information
8 with respect to a briefing by Perot Systems?
9 A. No, no, I don't recall anything about
10 that.
11 Q. Okay. Is it fair to say that Mr.
12 Sanders was the chief negotiator of the
13 settlement for the Silver Peak investigation?
14 A. I think so. I don't think we used
15 outside counsel. I think Richard handled that
16 settlement.
17 Q. Have you ever heard of the term "Black
18 Widow"?
19 A. I first heard that term in the process
20 of these depositions. I don't remember it --
21 obviously, it wasn't in our memo. And I can't
22 describe to you what it is. I don't know what
23 it means.
24 Q. Okay. Have you ever heard the term
25 "Big Foot"?

1 A. No. No.
2 Q. Have you ever heard the term "Cung
3 Catcher"?
4 A. No, no, I have not heard that term.
5 Q. Have you ever heard the term "Red
6 Congo"?
7 A. In the deposition, somewhere back in
8 there, that name came out. But I had not heard
9 it until that time.
10 Q. Okay. Have you ever heard of "Project
11 Green," or anything, quote, "Green"?
12 A. No. No.
13 Q. Ever heard of "Rolling Rock"?
14 A. No.
15 Q. Apart from being beer.
16 A. No. These are names that I haven't
17 heard. I have not heard.
18 MR. CHABOT: Okay. Just off
19 the record a second.
20 (Off the record)
21 MR. CHABOT: Okay. Back on.
22 BY MR. CHABOT:
23 Q. Have you had any discussions with anyone
24 in connection with the names that I've just read
25 to you, of those that you had heard of, that

1 you picked up in the depositions previous, have
2 you had any discussions with anyone about those
3 names?
4 A. No, I haven't. I don't know what they
5 involve.
6 MR. CHABOT: Off the record.
7 (Off the record)
8 MR. CHABOT: We're going to
9 take a five-minute break.
10 (Recess)
11 MR. CHABOT: Anybody that's not
12 here, tell me.
13 Five minutes has gone by, so we
14 will resume.
15 Back on the record.
16 BY MR. CHABOT:
17 Q. Have you ever heard the term "Coyote
18 Springs 2"?
19 A. Yes.
20 Q. And what is that?
21 A. It was a development, a power plant
22 development project in Eastern Oregon that EPMI
23 worked on.
24 Q. Who supervised that operations of Coyote
25 Springs 2?

1 A. Well, my limited understanding -- I
2 never worked on that project -- but my limited
3 understanding is that Portland General Electric
4 had a power plant there at Boardman called
5 "Coyote Springs 1," and they had a development
6 permit that had been approved through the Oregon
7 PUC to build a second generator there to go
8 with the first one.
9 And, somehow, Enron -- this
10 would have been -- the Enron Origination team
11 had worked through some kind of a deal to
12 develop that Coyote Springs 2 second generator.
13 And somehow -- my limited memory
14 is that somehow Avista was involved at the end
15 somehow.
16 That's the limited knowledge I
17 have of that transaction.
18 Q. Okay. Do you recall a December 12
19 meeting with Mr. Hall and Mr. Gibbs concerning
20 the San Diego class-action lawsuit?
21 A. Was that -- if it was the date that
22 Mr. Gibbs was in Portland for that class-action
23 meeting, if that was the big meeting that we
24 had in Portland, I don't recall Mr. Hall
25 specifically meeting alone with Mr. Gibbs, but

1 that's where a conversation might have occurred,
2 if it's at that date.
3 Q. Uh-huh. Do you recall what, if anything
4 -- well, let's --
5 MR. CHABOT: Off the record.
6 (Off the record)
7 MR. CHABOT: Let me restate it
8 on the record.
9 While off the record I've asked
10 the witness to look at Bate-stamped page AA,
11 last three digits 192, which is a bill from the
12 Stoel Rives law firm to Enron North America,
13 dated January 30, 2001, and with particular
14 reference to the entry for December 12, 2000.
15 BY MR. CHABOT:
16 Q. And my first question is, Does this
17 refresh your recollection about it?
18 A. Yes, it does.
19 Q. Okay. And, to the best of your
20 recollection, what occurred at that meeting?
21 A. To the best of my recollection, that was
22 the big December meeting that I talked about
23 earlier, where the class-action lawsuit litigation
24 team had come to town, and we were briefing
25 them on some of the trading issues that were

1 going on.
2 Q. Okay. When I was questioning you
3 earlier I had in mind the December 7th meeting,
4 which you'll see referenced at AA191, the
5 preceding page.
6 A. 12-7 -- you mean at the bottom here?
7 Q. Correct, yes.
8 A. To me, that's a preliminary discussion.
9 "Conference with Marcus Wood and
10 Christian Yoder" --
11 I thought -- as that flows on,
12 the description of his work, he talks about
13 preparing for presentation to San Diego legal
14 team, on 12-11.
15 And, then, on 12-12 we had the
16 meeting with the San Diego legal team. And I
17 would see the meeting on the 7th as being the
18 final meeting -- one of the final meetings where
19 we actually went over the trading strategies memo
20 draft with Marcus Wood from Stoel Rives and
21 approved it. You know, said, "Yeah, let's give
22 this to the team when they come to help them
23 focus themselves."
24 That would be my understanding
25 of that, that 12-7 meeting.

1 Q. Okay. Based on the fact that there
2 were both meetings on December 7th and December
3 12th, is there anything that you've said earlier
4 today that requires modification?
5 A. No, no, it would have been all the
6 same. We were working to understand and write
7 clearly what our perceptions of the strategies
8 were for the meeting on -- whenever it happened,
9 which it looks like it was the 12th.
10 Q. Do you hold any position in LJM 1? Do
11 you know what LJM 1 is?
12 A. Well, I have to think about that a
13 second.
14 No, I don't hold or didn't hold
15 any position in LJM 1.
16 Q. LJM 2?
17 A. No.
18 Q. South Hampton Place?
19 A. No.
20 Q. Rawhide?
21 A. No.
22 Q. Hawaii?
23 A. No.
24 Q. Or any other Enron-related partnership?
25 A. No.

1 Q. Okay. Do you know any of the following
2 individuals: Robert Scorrano, S-c-o-r-r-a-n-o?
3 A. No.
4 Q. Steve Tish, T-i-s-h?
5 A. No.
6 Q. David Pierce, P-i-e-r-c-e?
7 A. No.
8 Q. Mark Whorton, W-h?
9 A. No.
10 Q. Bob Leech, L-e-e?
11 A. No.
12 Q. Robert Lawrence?
13 A. No.
14 Q. Paulin, P-a-u-l-i-n, D'Almeida,
15 D-'-A-l-m-e-i-d-a?
16 A. No.
17 Q. Joe Lingold?
18 A. No.
19 Q. Ben Borgen, B-o-r-g-e-n?
20 A. No.
21 Q. During the discussions that commenced
22 October 3rd, was there any -- and continuing
23 throughout the period until they concluded -- was
24 there any discussion of Enron online?
25 A. It -- it was not -- no, it was not a

1 prominent -- I can't recall where that issue was
2 focused on in a -- no, my answer is no.
3 Q. Okay.
4 MR. CHABOT: Off the record.
5 (Off the record)
6 (Whereupon, a volume of various
7 documents was marked Exhibit-3 for
8 identification.)
9 MR. CHABOT: Let's go back on
10 the record, then, please.
11 BY MR. CHABOT:
12 Q. Off the record I've asked you to take a
13 look at the handwritten pages, and the notations
14 appearing in your deposition Exhibit No. 3. And
15 have you done so?
16 A. Yes, I have.
17 Q. And based on that review are there any
18 -- is there any of the handwriting there that
19 you can identify?
20 A. I recognize my initials on the Stoel
21 Rives legal bills. And, other than that --
22 I've come to -- I've come to know that some of
23 those notes are attributed to Mary Hain; but, as
24 I said before, I would not recognize her
25 handwriting.

1 Q. Okay.
2 A. Other than that, no.
3 Q. And earlier I had asked you whether you
4 had taken notes at the October 3rd meeting, but
5 I neglected to ask whether you had taken notes
6 at any of the meetings other than October 3rd
7 or of any of your conversations with Mr. Hall?
8 A. No, I didn't take notes on those
9 matters.
10 MR. CHABOT: Okay. I would
11 next like to have marked as your deposition
12 Exhibit No. 4, a five-page document. It appears
13 to be an e-mail transmission. It's dated July 9
14 of 2001. It bears a Bate stamp EC071007372
15 through 76.
16 And I will state that this was
17 provided to us by Senator Dunn from California.
18 If we can have that marked.
19 (Whereupon, an e-mail
20 transmission, five-page document, was marked
21 Exhibit-4 for identification.)
22 BY MR. CHABOT:
23 Q. You are included there among the
24 addressees of the memo from Stephen Hall; is
25 that correct?

1 A. Yes, I see my name there.
2 Q. Okay. Do you recall having seen this
3 or read in electronic form this memorandum
4 earlier?
5 A. Well, I have to look at it here.
6 I see this --
7 MR. CHABOT: Off the record
8 until you're ready to talk.
9 (Off the record)
10 MR. CHABOT: Back on the
11 record.
12 THE WITNESS: This appears to
13 me, as I look at it, to be a message that
14 Steve sent to -- from Steve Hall to Mark
15 Palmer, in which he included a transcript of
16 some tapes that we had -- that he had done.
17 And my first -- oh, right, it's
18 referring to Ryan Slinger and the realtime desk.
19 And this -- I'm assuming this
20 is about the incident where the California ISO
21 allegedly approached Enron's realtime desk to do
22 a transaction that allegedly had some implication
23 on realtime pricing.
24 That's what it looks like to
25 me.

1 Q. Okay. And do you have any memory of
2 having received this?
3 A. I remember Steve being involved in
4 tracking down the conversation and doing it, so
5 it doesn't surprise me that my name would appear
6 in the -- you know, to the people that it's
7 addressed to. But I don't -- I don't remember
8 the discussions with upper management, with Mark
9 Palmer, Steve Kain. I didn't take part in
10 those discussions. But I remember when he was
11 working on documenting that conversation.
12 Q. Okay. And do you recognize the
13 handwriting that appears on the first page of
14 this?
15 A. No, I'm sorry, I don't.
16 Q. With regard to the long-term contracts
17 that you were responsible for that we talked
18 about earlier, who would have custody of those
19 documents at Enron today?
20 A. Well, my files, my Enron files, were, of
21 course, turned over to Enron when I left in
22 February of this year, and Enron would have
23 custody of them. And my understanding was that
24 they were all given to a storage agency that
25 stored them here in Portland; all of the

1 Portland Enron files.
2 Q. Okay. Do you know the name of any
3 individuals that would have responsibility for
4 them?
5 A. No. You would have to call the Enron
6 Portland office. And, I'm sorry, I don't --
7 they're one floor up, but I don't have their
8 number.
9 Q. Right. Do you know the name of the
10 storage company?
11 A. I think -- it might have been Iron
12 Mountain. But don't quote me on that. Yeah, I
13 think it was Iron Mountain Storage. We were
14 all -- we were asked to go through our records
15 and hand them all over, and give them to -- and
16 that's where my long-term contract notes and
17 files would be, in that -- in that repository.
18 Q. Okay.
19 A. As far as I know.
20 Q. The executed -- would that be the
21 executed contracts themselves or --
22 A. No, executed -- the practice I followed
23 was to negotiate the contracts. And the
24 original executed versions would have been sent
25 down to Houston. Enron had a repository for

1 executed documents there. And we would have
2 kept a photocopy in a notebook just for our own
3 records in the Portland office.
4 Q. Okay. So it's the photocopy that you
5 believe is --
6 A. Yes.
7 Q. -- in storage?
8 A. Yeah, that would be there.
9 Q. Who would have, if you know, would have
10 responsibility over the archives in Houston?
11 A. Well, I don't know who has it now. I
12 always sent them to a contract administration
13 person down there, and her name was Rhonda
14 Denton. And she no longer works at Enron. But
15 she was responsible for collecting all of the
16 originals and keeping them in some ordered place
17 down there.
18 MR. CHABOT: All right. That's
19 all I have here.
20 Does anyone have any cross or
21 redirect?
22 I guess it's all cross now,
23 isn't it?
24 MS. MCFARQUHAR: This is Erica
25 McFarquhar. I would like to reserve my

1 questions for a later date.
2 MR. CHABOT: I think we can
3 stipulate that for everybody.
4 Anything from anyone else?
5 That being said, not hearing
6 from anyone, we will shut this down.
7 Thank you all.
8 (Deposition concluded at 3:02
9 p.m.)
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CERTIFICATE

I, Gary W. Koch, do hereby certify that pursuant to the Rules of Civil Procedure, the witness named herein appeared before me at the time and place set forth in the caption herein; that at the said time and place, I reported in stenotype all testimony adduced and other oral proceedings had in the foregoing matter; and that the foregoing transcript pages constitute a full, true and correct record of such testimony adduced and oral proceeding had and of the whole thereof.

IN WITNESS HEREOF, I have hereunto set my hand this _____ day of _____, 2002.

_____ _____

Signature Expiration Date

Committee on Governmental Affairs
EXHIBIT #A-66

COPY OF TRANSCRIPT

UNITED STATES OF AMERICA
BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

Nevada Power Company and
Sierra Pacific Power Company,

Complainants,

vs. Docket Nos. EL02-26-000, EL02-28-000, EL02-33-000, and EL02-38-000

Duke Energy Trading and Marketing L.L.C., Enron Power Marketing, Inc., El Paso Merchant Energy, and El Paso Merchant Energy, and American Electric Power Services Corp,

Respondents.

Nevada Power Company,

Complainant,

vs. Docket Nos. EL02-29-000, EL02-30-000 EL02-31-000, EL02-32-000, EL02-34-000, EL02-39-000

Morgan Stanley Capital Group, Calpine Energy Services, and Reliant Energy Services, Mirant Americas Energy Marketing, L.P., Mirant Americas Energy Marketing, L.P., BP Energy Company, and Allegheny Energy Supply Company, L.L.C.

Respondents.

COPY OF TRANSCRIPT

Southern California Water Company,

Complainant,

vs.

Mirant Americas Energy Marketing, L.P.,

Respondent.

DEPOSITION OF STEPHEN C. HALL
Taken on behalf of the City of Tacoma
Thursday, July 11, 2002

- - -

BE IT REMEMBERED THAT, pursuant to the Civil Rules of Procedure, the deposition of STEPHEN C. HALL was taken before Phillip A. Rader, a Notary Public for the State of Oregon, on July 11, 2002, commencing at the hour of 9:00 a.m.; the proceedings being reported at the law offices of Stoel Rives, 900 S.W. Fifth Avenue, Suite 2600, Portland, Oregon 97204.

1 APPEARANCES

2 McGUIRE WOODS

3 PHILIP L. CHABOT, JR.

4 1050 Connecticut Avenue N.W.

5 Suite 1200

6 Washington, D.C. 20036-5317

7 (202) 857-1700

8 Appearing on behalf of the City of Tacoma

9 .

10 STEPTOE & JOHNSON

11 MARK HULKOWER

12 1330 Connecticut Avenue

13 Washington, D.C. 20036

14 (202) 429-3000

15 Appearing on behalf of the witness

16 .

17 STOEL RIVES

18 JOEL A. MULLIN

19 900 S.W. Fifth Avenue

20 Suite 2600

21 Portland, Oregon 97204

22 (503) 294-9665

23 Appearing on behalf of the witness

24 .

25 LeBOEUF, LAMB, GREENE & MacRAE

1 CHARLES MOORE
2 1000 Louisiana
3 Suite 1400
4 Houston, Texas 77002-5009
5 (713) 287-2086
6 Appearing on behalf of Enron Power Marketing,
7 Inc.
8
9 FEDERAL ENERGY REGULATORY COMMISSION
10 DENNIS MELVIN
11 888 - 1st Street N.E.
12 Washington, D.C. 20426
13 (202) 208-0042
14 Appearing on behalf of the Federal Energy
15 Regulatory Commission
16
17 LATHAM & WATKINS
18 JOEL ARD
19 555 - 11th Street N.W.
20 Suite 1000
21 Washington, D.C. 20004
22 (202) 637-1034
23 Appearing on behalf of Mirant Americas Energy
24 Marketing
25

1 ENERGY & RESOURCE CONSULTING GROUP
2 PHILLIP MORVISH
3 8055 Tufts Avenue
4 Suite 1250
5 Denver, Colorado 80237
6 (303) 843-0600
7 Consultant for the City of Tacoma
8 .
9 SULLIVAN & WOOSTER
10 ORLANDO VIDAL
11 1666 K Street N.W.
12 Washington, D.C. 20006
13 (202) 775-6825
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1 PORTLAND, OREGON;
2 THURSDAY, JULY 11, 2002
3 9:00 A.M.
4
5 MR. CHABOT: My name is Phil
6 Chabot. I have given the reporter my address.
7 I'm appearing on behalf of the City of Tacoma.
8 MR. HULKOWER: Mark Hulkower.
9 I have given the reporter my address. I'm
10 appearing on behalf of Stephen Hall, the
11 deponent.
12 MR. MULLIN: Joel Mullin. He
13 has my card. I'm appearing on behalf of Stephen
14 Hall, the deponent.
15 THE WITNESS: Stephen Hall, the
16 deponent.
17 MR. MOVISH: This is Phillip
18 Movish, M-O-V-I-S-H. I'm a consultant to the
19 City of Tacoma. My business address is Energy
20 and Resource Consulting Group, LLC, 8055 E. Tufts
21 Avenue, T-U-F-T-S, Suite 1250, Denver, Colorado
22 80237. My office phone number is 303-843-0600.
23 MR. MOORE: Charles A. Moore.
24 I'm with the law firm of Labouef, Lamb, Green
25 and McCrea, LLP. L-A-B-O-U-E-F, L-A-M-B, G-R-E-E-N

1 and M-C-C-R-E-A. I'm appearing on behalf of
2 Enron Power Marketing, Inc. My mailing address
3 is 1000 Louisiana, Suite 1400, Houston, Texas
4 77002-5009. My telephone is 713-287-2086. My
5 e-mail is cmoore@llg.com. I would like a copy
6 of the transcript and exhibits.
7 MR. ARD: This is Joel Ard,
8 A-R-D. I'm with the Lathum and Watkins. We
9 are at 555 - 11th Street N.W., Suite 1000,
10 Washington, D.C. 20004. My phone number is
11 202-637-1034. We would also like a copy of the
12 transcript and exhibits.
13 MR. MELVIN: And also appearing
14 by telephone, this is Dennis Melvin, M-E-L-V-I-N.
15 I represent the trial staff at the FERC, the
16 Federal Energy Regulatory Commission. My address
17 is 888 - 1st Street N.E., Washington D.C. 20426.
18 My telephone is 202-208-0042. We are not asking
19 for a copy of the transcript at this time.
20 MR. CHABOT: Was there anyone
21 else on the line?
22 Mr. Rader, the court reporter,
23 prior to the time that we began indicated that
24 there were parties that had requested overnight
25 service. And I just want to confirm --

1 (Discussion off the record.)
2 MR. CHABOT: Could I ask Mr.
3 Vidal to enter his appearance, please.
4 MR. VIDAL: This is Orlando
5 Vidal on behalf of the Public Utility District
6 No. 1 of Snohomish County, Washington.
7 MR. CHABOT: Could you give
8 your address.
9 MR. VIDAL: I'm at Sullivan and
10 Wooster, 1666 K Street N.W., Washington D.C.
11 20006.
12 MR. CHABOT: The reporter would
13 like a telephone number as well.
14 MR. VIDAL: 202-775-6825.
15 MR. CHABOT: Just before Mr.
16 Vidal joined us, I was indicating that prior to
17 our going on the record this morning the court
18 reporter indicated that it was his understanding
19 that at least one party, possibly more, had
20 requested overnight service on the transcript. I
21 just wanted to see if, in fact, there was any
22 party that did, in fact, require overnight
23 service.
24 MR. MOORE: I will not need
25 overnight service. How long would it take

normally?

MR. CHABOT: The indication is a week to 10 days.

MR. MOORE: That will be fine.

MR. VIDAL: That's also fine with Snohomish.

MR. CHABOT: You are going to have to state your name. That was Mr. Vidal. If you are going to make statements on the line, you are going to have state your name before you make it.

Based on what I have heard, unless there is an objection in the next few seconds, I'm going to ask the reporter to do regular service to all parties that have requested transcripts.

Are there any other preliminaries before we swear the witness?

Hearing none, I'll ask the reporter to swear the witness.

STEPHEN C. HALL,

having first been duly sworn, was examined and testified as followed:

EXAMINATION

1 BY-MR.CHABOT:
2 Q. Mr. Hall, could you please state your
3 full name.
4 A. Stephen C. Hall.
5 Q. What is your current residence and
6 business address?
7 A. My current residence address is 2515
8 N.E. 39th Avenue, Portland, Oregon 97212.
9 Business address is 321 S.W. Salmon Street, Suite
10 302, Portland, Oregon 97204.
11 Q. By whom are you employed now?
12 A. UBS Warburg Energy.
13 Q. Mr. Hall, are you currently on any
14 medication or taking any drugs that would affect
15 your ability to give testimony this morning?
16 A. No.
17 Q. I'd like to show you a copy of a
18 document, a Subpoena Duces Tecum. This copy is
19 signed by Judge Cintron. I'll ask if you are
20 appearing today in response to that subpoena.
21 MR. HULKOWER: Phil, do you
22 want that marked?
23 MR. CHABOT: We are going to
24 mark it, yes.
25 A. This appears to be the subpoena.

1 MR. CHABOT: We would like to
2 have this marked as Hall Deposition Exhibit No.
3 1.
4 (Whereupon, a Subpoena Duces
5 Tecum was marked Exhibit-1 for identification.)
6 BY MR. CHABOT:
7 Q. Mr. Hall, did you bring with you today
8 any documents that were responsive to the
9 Subpoena Duces Tecum?
10 A. I did not.
11 Q. Do you have in your possession, custody
12 or control any documents that would be responsive
13 to the Subpoena Duces Tecum?
14 A. I do not.
15 Q. Could you please just give a brief
16 description of your academic credentials.
17 A. Certainly. I have a Bachelor's Degree
18 in business administration from Western Michigan
19 University. I have a law degree from the
20 University of Notre Dame Law School.
21 Q. When did you obtain your BA?
22 A. 1992.
23 Q. And your law degree?
24 A. 1996.
25 Q. What has been your employment background

1 since '96 to the present time?
2 A. After I graduated from law school, I did
3 a clerkship for one year with the Chief Justice
4 of the Michigan Supreme Court. In 1997, I
5 joined Stoel Rives. In June 2001, I joined
6 Enron. In February 2002, I joined UBS Warburg
7 Energy.
8 (Discussion off the record.)
9 BY MR. CHABOT:
10 Q. At what office of Stoel Rives were you
11 located?
12 A. The Portland office.
13 Q. I assume you were an associate there?
14 A. Yes.
15 Q. Who was your immediate supervisor, if
16 any, or supervisors?
17 (Discussion off the record.)
18 A. I think the question was, who was my
19 supervisor here? When I joined the firm, I
20 joined the litigation department, and the head of
21 that practice group was Craig Mowe at that time,
22 M-O-W-E. And then in 2000, I joined the Energy
23 Group at Stoel Rives, and the head of the
24 practice group at that time was Jim Fell.
25 Q. Could you spell Mr. Fell's name.

1 A. J-I-M, F-E-L-L.
2 Q. And you stayed with the Energy Group
3 until June of 2001 when you went directly to
4 Enron?
5 A. Yes, to Enron North America.
6 Q. I take it that in the time prior to
7 June of 2001, you had occasion to be working on
8 behalf of Enron?
9 A. Yes.
10 Q. Could you describe briefly what those
11 projects involved.
12 A. Sure. Starting in September of 2000,
13 Marcus Wood, a partner in the Energy Group at
14 Stoel Rives, asked me to familiarize myself with
15 the California ISO and the California PX tariffs
16 to be able to advise Enron on matters related to
17 that and to assist in-house counsel, Christian
18 Yoder, with preparation, drafting and the
19 negotiation of master energy trading contracts.
20 And from that time until June 2001, I assisted
21 Mr. Yoder with tasks of that nature, and many
22 countless small projects, small research projects,
23 and negotiations and drafting matters.
24 Q. Prior to September of 2000, had you had
25 any prior experience with the California ISO and

1 PX tariffs?
2 A. No.
3 Q. Any other form of electric tariffs?
4 A. I was familiar with the tariffs of BPA,
5 their transmission tariffs, and generated
6 schedules.
7 Q. And similarly prior to September of
8 2000, had you had any previous involvement on
9 master trading contracts?
10 A. No.
11 Q. Prior to the time that you went directly
12 to Enron, June of 2000, was there a time during
13 which you were detailed to Enron?
14 A. What do you mean by "detailed"?
15 Q. Given a more or less permanent
16 assignment that would put you in their offices.
17 A. Once I started working with Mr. Yoder --
18 the Stoel Rives office and the trading floor
19 here in Portland are three blocks apart. And I
20 would spend part of the day at Stoel Rives and
21 part of the day over on the trading floor. And
22 sometimes in a day, I might walk back and forth
23 three or four times, depending on where my
24 responsibilities were.
25 Starting in September of 2000,

1 when I was working for Enron, I had other
2 clients, other matters, and they were just one
3 of my clients.
4 Q. In the period prior to the time you
5 went to Enron on a permanent basis, in addition
6 to the Enron trading floor, the Enron North
7 America trading floor, did you have occasion to
8 go to the PG&E trading floor?
9 A. I did not.
10 Q. Did you have occasion to have any
11 contacts with PG&E?
12 A. Very minimal contacts.
13 Q. What would they involve?
14 A. Just to be clear, did you say prior to
15 September of 2000?
16 Q. Correct.
17 A. Prior to September of 2000, no.
18 MR. MOORE: This is Charlie
19 Moore. I hate to interrupt. But both of you
20 need to move closer to the microphone, if you
21 can, or speak up. We're having difficulty
22 hearing.
23 MR. CHABOT: We'll try to speak
24 up. We're pretty close.
25 MR. MOORE: Thank you.

1 MR. CHABOT: To expedite the
2 cross examination, we have compiled a group of
3 three sets of documents. The first volume of
4 tab attachment AB consists of a series of
5 memoranda that were released by the Federal
6 Regulatory Commission earlier this year. The
7 second part tabbed AA consists of documents that
8 were provided by the Attorney General of
9 California in support of a motion to reopen the
10 Puget proceeding in the Federal Regulatory
11 Commission.
12 The second volume consists of a
13 set of documents that was provided to us by
14 Senator Dunn of California in connection with the
15 staff and committee hearing investigations in
16 California.
17 What I would like to do is to
18 have Volume 1 marked as your Deposition Exhibit
19 No. 2 and Volume 2 marked as your Deposition
20 Exhibit No. 3. They are all Bate-stamped.
21 We'll refer to the pages by Bates stamps, so
22 we'll have one set of documents and go from
23 there.
24 Let's go off the record while
25 we do that process.

1 (Discussion off the record.)
2 (Whereupon, Volume 1 was marked
3 Exhibit-2 and Volume 2 was marked Exhibit-2 for
4 identification.)
5 MR. CHABOT: We are back on the
6 record.
7 BY MR. CHABOT:
8 Q. Let's begin with the document grouping,
9 the AB document grouping, that consists of the
10 memorandum, the Stoel Rives memorandum. Your
11 name appears as one of the two authors on the
12 document beginning at the AB series of 0's, the
13 last digit being 1.
14 Is it fair to say that you are
15 familiar with the documents that appear at AB 1
16 through AB 21?
17 MR. HULKOWER: For the record,
18 you are talking about the December 6, 2000,
19 Stoel Rives memo, and the December 8, 2000,
20 Stoel Rives memo, and the undated draft of the
21 Gary Fergus and Jean Frizzell memo?
22 MR. CHABOT: That is correct.
23 A. These appear to be the two memoranda
24 that I drafted. I'm familiar with those two
25 memos. The other memo, I read through it

1 recently.
2 BY MR. CHABOT:
3 Q. Okay. Am I also correct that these
4 memoranda were prepared following a series of
5 meetings, the first of which occurred on or
6 about October 3rd of 2000?
7 A. I can only speak to the preparation of
8 my two memoranda. And yes, they were prepared
9 in response to an October 3rd meeting.
10 Q. Could you describe, then, what events
11 occurred prior to October 3rd that led to the
12 October 3rd meeting.
13 A. Enron Power Marketing had received a
14 subpoena from -- I believe it was the California
15 Public Utility Commission. And in response to
16 that subpoena, Richard Sanders, the head of
17 litigation for Enron North America, convened a
18 meeting in Portland, Oregon, to discuss how to
19 respond to that subpoena.
20 Q. Did you attend that meeting?
21 A. Yes, I did.
22 Q. Were there any other Stoel Rives
23 participants at that meeting?
24 A. No.
25 Q. What, if any, preparations were taken by

1 you in advance of that meeting?
2 A. None that I recall.
3 Q. To the best of your recollection -- and
4 I understand we're talking about a day-long
5 meeting -- but could you recall the names of the
6 persons who were in attendance.
7 A. Tim Belden was there. Christian Yoder
8 was there. Richard Sanders, Gary Fergus, Dan
9 Watkiss, Mary Hain. Perhaps Paul Kaughman. Jim
10 Steffis. Possibly Jeff Dasavitch. That's all I
11 recall.
12 Q. Do you recall Mr. Seborn Adamson being
13 there?
14 A. He may have been. I don't recall him
15 being there one way or the other. But he may
16 have been.
17 Q. Again, to the best that you can, if you
18 could relate what was said in the course of that
19 meeting and by whom.
20 A. As I said, the purpose of the meeting
21 was to respond to the CPUC subpoena -- the
22 California Public Utility Commission subpoena.
23 That was the purpose of the meeting. Christian
24 Yoder, who I was working with, suggested that I
25 might benefit from attending the meeting, because

1 at some point the traders were going to be
2 discussing their trading strategies. And Mr.
3 Yoder said to me that this would be the first
4 time that he knew of that the traders had ever
5 explained what they did in kind of an open
6 format where the attorneys could learn about it.
7 Q. Excuse me for interrupting.
8 So the request for you to
9 attend came directly from Mr. Yoder to you?
10 A. Yes. I wasn't there because I was
11 advising Enron on responding to the subpoena. I
12 was just there because I happened to be over on
13 the trading floor working with Mr. Yoder, and he
14 thought it would be educational and beneficial
15 for me to attend the meeting.
16 Q. Okay. So at that point -- I'm sorry to
17 interrupt -- but you had no prior involvement
18 with the CPUC subpoena, or were even aware that
19 it existed?
20 A. I probably was aware that it existed,
21 and probably found out through Mr. Yoder as soon
22 as it arrived.
23 Q. But you had no assignment with respect
24 to it?
25 A. I wasn't the attorney who was in charge

1 of responding to it.
2 Q. At Enron, do you know who those
3 attorneys were?
4 A. Mr. Sanders was the head of litigation
5 for Enron North America. So within the company,
6 he would have had responsibility for responding
7 to that. And my understanding is that he had
8 retained Mr. Fergus from the Brobeck firm.
9 Q. Were there other attorneys at Stoel
10 Rives that would have had any responsibilities in
11 connection with this subpoena?
12 A. Not that I'm aware of.
13 Q. If you could continue, then.
14 A. It was a somewhat large meeting in a
15 somewhat small conference room. And at some
16 point in the meeting, I remember Mr. Belden
17 giving an introduction about the California
18 energy market, explaining the California --
19 explaining the California Power Exchange and the
20 California Independent System Operator, or ISO,
21 explaining how those markets worked and
22 describing the basics of how energy was
23 scheduled.
24 After his introduction, the
25 trading strategies were -- the names were written

1 on a white erasable board, and Mr. Belden talked
2 about --
3 Q. Excuse me, when you say "names," what
4 names?
5 A. The names of the trading strategies.
6 Q. I see.
7 A. They were written on the white erasable
8 board, and the strategies were explained to the
9 group. And that was the first time that I had
10 learned of the trading strategies.
11 Q. When you say the names of the trading
12 strategies were listed on the board, were those
13 the names that later appeared in your December
14 6th and subsequent memorandum?
15 A. Yes.
16 Q. Were there any names other than those
17 that appeared in your December 6th and subsequent
18 memorandum?
19 A. That were written on the board?
20 Q. Right.
21 A. I don't think so.
22 Q. Did anything further take place after
23 Mr. Belden's presentation?
24 A. The trading strategies were explained.
25 Other traders got up and explained different

1 strategies. And the traders finished, as I
2 recall -- after they had finished the
3 presentation, I believe that they left. And the
4 attorneys and regulatory people in the room had
5 a discussion after the traders left.
6 Q. Okay. You indicated after Mr. Belden
7 finished speaking other traders got up and
8 discussed different strategies.
9 A. Yes.
10 Q. I want to be clear. Were those
11 strategies different than those that were listed
12 on the board, or was it just a different
13 discussion of those strategies?
14 A. It was different people describing
15 different strategies, but within that same
16 universe of the list of names that were up
17 there.
18 Q. Okay. Again, to the best of your
19 ability, can you relate after the traders left
20 what was said and by whom.
21 A. I don't recall the exact substance of
22 the conversation. But my memory at this time is
23 that there was a discussion about the strategies,
24 just trying to understand them, and there was
25 not much of a consensus in the room about what

1 we had just heard. The strategies were complex,
2 and it didn't seem that anybody had a good
3 understanding of what they had just explained --
4 of what had just been explained to the group.
5 Q. Was Ms. Hain present?
6 A. Ms. Hain was there.
7 Q. Did you have the impression that any of
8 the participants in the room had been aware of
9 any of these strategies prior to this meeting,
10 other than the traders?
11 A. No. But obviously I don't know what
12 they knew.
13 Q. Did you take notes during the meeting?
14 A. I did.
15 Q. Do you know what happened with those
16 notes?
17 A. I took the notes and incorporated them
18 into the memorandum that you have in front of
19 you.
20 Q. But in terms of their physical
21 disposition, do you know where they are now?
22 A. If they still exist after I incorporated
23 them into the memo, they would either be at
24 Stoel Rives or they would be with Enron.
25 Q. Do you recall having discarded the notes

1 after preparing the memo?
2 A. No.
3 Q. Do you know if anyone else took notes?
4 A. I believe others took notes.
5 Q. Do you recall with any specificity as to
6 who that was?
7 A. No.
8 Q. Were there any after-meeting memoranda
9 prepared?
10 A. Yes --
11 Q. Apart from your December 6th memo. I'm
12 talking about minutes of the meeting or something
13 of that sort.
14 A. No, not that I'm aware of.
15 Q. Although there was no consensus, as you
16 stated, was there any decision or recommendations
17 reached as to what would be the next phases of
18 action or investigation?
19 A. Well, with respect to one incident that
20 was brought up at that meeting, there was an
21 incident that Mr. Sanders testified to in front
22 of the senate about the rounding incident. On
23 that one, action was taken right there: Send
24 the money back to the California ISO.
25 The purpose of the meeting was

1 responding to the subpoena, so any action plan
2 after that, I think, would have focused on
3 responding to the subpoena. With respect to the
4 trading strategies, my memory is that the goal
5 was to understand the trading strategies.
6 Q. What, if anything, was decided with
7 respect to getting a better understanding of
8 those trading strategies?
9 A. I don't recall anybody making a specific
10 statement about it. My sense is that Mr. Fergus
11 was going to work and understand those. The
12 next day Mr. Yoder asked me to learn about and
13 describe the trading strategies and to write it
14 up into a memorandum.
15 MR. HULKOWER: Excuse me.
16 (Discussion off the record.)
17 A. I also remember that someone asked me to
18 write up my notes at the end of the meeting and
19 to distribute those to the group. I remember
20 some comment of, well, you seem to have some
21 pretty good notes here, why don't you write
22 those up.
23 BY MR. CHABOT:
24 Q. Okay. Did you do that?
25 A. I did. But I don't remember

1 distributing them. I think that I probably
2 started to write them up, and I went and talked
3 to Mr. Yoder the next day, and he said: Why
4 don't you prepare something more formal and put
5 this into a memorandum. And I went about
6 describing the strategies.
7 Q. So following the meeting on October 3rd,
8 was there a meeting on October 4th as well?
9 A. I don't believe so.
10 Q. October 5th?
11 A. I don't believe so. Do you mean to
12 respond to the subpoena?
13 Q. On issues related to the Enron trading
14 strategies.
15 A. I don't specifically remember when.
16 Q. What did you do then to respond to Mr.
17 Yoder's suggestion that you investigate further?
18 A. I took the notes that I had written up,
19 and that became the basis for my memorandum.
20 And then I had informal discussions with traders
21 to try to understand the technical aspects of
22 these trading strategies, how things were
23 scheduled, how bids were put in, that sort of
24 thing. I studied the California ISO and the
25 California PX tariff, which I was still

1 familiarizing myself with, and compared the
2 strategies with the tariff and tried to
3 understand how the rules with those markets
4 worked in relation to those strategies.
5 Q. Now, my understanding was that there was
6 another meeting approximately a month after the
7 October 3rd meeting?
8 A. Yes.
9 Q. Do you recall the date of that?
10 A. It was approximately one month later.
11 Q. So is it fair to say, then, that in the
12 period between October 3rd and the November
13 meeting, that you were in the process of
14 conducting these interviews and doing the
15 research that Mr. Yoder had requested?
16 A. Yes.
17 Q. Did you conduct the interviews with the
18 traders on a one-on-one basis?
19 A. Yes.
20 Q. Do you recall the interviews with the
21 traders with whom you met?
22 A. I would have spoken with traders from
23 the real time desk and traders from the
24 California -- they have a short-term desk.
25 Q. Do you remember the names?

1 A. I remember speaking with Jeff Richter
2 and Chris Mallory and John Forney. I may have
3 spoken with others at that time.
4 Q. You mentioned Mr. Forney. If I repeat
5 some of the names that you have already
6 mentioned, I apologize.
7 How about Michael Driscoll, did
8 you ever speak with him?
9 A. I may have spoken to Michael Driscoll.
10 Q. Who was Michael Driscoll?
11 A. Mike worked on the real time desk.
12 Q. Lester Ranson?
13 A. I don't know a Lester Ranson. I think
14 you mean Les Rowson.
15 Q. Rowson, R-O-W-S-O-N.
16 A. I don't remember speaking to Mr. Rowson
17 about the trading strategies.
18 Q. By "trading strategies," I'm not
19 referring to just the strategies that were
20 discussed on October 3rd, but any of the other
21 Enron practices with respect to the California
22 ISOs or the Enron markets.
23 A. Do you mean a group of something that
24 even existed bigger than what is in the
25 memorandum?

1 Q. Yes.
2 A. Maybe we should define what you mean by
3 that.
4 All of the strategies that were
5 presented on October 3rd are incorporated into
6 the memorandum. There were not other strategies
7 that I was also learning about to put in the
8 memorandum.
9 Q. Okay. Let me restrict my question,
10 then, to the list of names that I'm going to
11 read. I'll restrict it just to the subjects
12 discussed in your December 6th and December 8th
13 memoranda.
14 A. Okay.
15 Q. Donald Smith?
16 A. Was he an Enron employee?
17 Q. I just have a name.
18 A. I don't recall meeting with a Donald
19 Smith.
20 Q. Valery Sabo, S-A-B-O.
21 A. No.
22 Q. Scott McKinley?
23 A. No.
24 Q. Cory Morris?
25 A. No.

1 Q. Larry Dougherty?
2 A. No.
3 Q. Stuart Brosman?
4 A. No.
5 Q. Jeffrey Miller?
6 A. No.
7 Q. Bill Casey?
8 A. No.
9 Q. Peter Limon?
10 A. No.
11 Q. Walt Pollock?
12 A. No.
13 Q. Rich Davis?
14 A. No.
15 Q. Marlene Hutsinger?
16 A. No.
17 Q. Al Alexanderson?
18 A. No.
19 Q. Pamela Lesh?
20 A. No.
21 Q. Peggy Fowler?
22 A. No.
23 Q. Did you at any time, prior to the
24 December 6th and December 8th memos, hear the
25 term "Black Widow"?

1 A. No.
2 Q. Big Foot?
3 A. No.
4 Q. Conn Catcher, C-O-N-N?
5 A. No.
6 Q. Red Condo?
7 A. No.
8 Q. Coyote Springs?
9 A. Yes.
10 Q. Green?
11 A. Green?
12 Q. Just plain Green. Green, the color
13 green.
14 MR. HULKOWER: In the context
15 of a trading strategy.
16 A. No, not in the context of a trading
17 strategy.
18 Q. Rolling Rock?
19 A. No.
20 Q. Silver Peak?
21 A. I'm aware of Silver Peak in the context
22 of it being one of transmissions, hub. And two,
23 that there was an incident with EPMI and the CAL
24 PX involving Silver Peak.
25 Is that what you are referring

1 to?
2 Q. That's one reference in which I'm
3 referring to it. I'm trying to find out if
4 there might be others.
5 A. There is no other context in which I'm
6 familiar with it.
7 Q. Did you at any time, prior to your
8 December 6th and December 8th memoranda, learn of
9 any other Enron trading strategies similar to
10 those identified in the December 6th memo but
11 not listed in the December 6th memo?
12 A. No.
13 Q. To the best of your recollection, what
14 was involved in Silver Peak?
15 A. Silver Peak was a dispute between EPMI
16 and the California Power Exchange. I think it
17 happened sometime in 1999, well before -- two
18 years or so before my involvement with working
19 for Enron North America. I think the crux of
20 the dispute was that EPMI had scheduled a
21 quantity of energy greater than the capacity for
22 that tie point, and the CAL PX initiated some
23 kind of dispute resolution or sanctioning process
24 against the EPMI. And the matter was ultimately
25 settled for, I think, like a $25,000 fine and no

1 admission of wrongdoing.
2 Q. Do you recall who, if anyone, at Enron
3 was responsible for implementing Silver Peak?
4 A. I don't know who was responsible for
5 implementing it. I was aware that Tim Belden
6 had testified during that process.
7 Q. Had you heard mentioned the name Perot
8 Systems in connection with Silver Peak?
9 A. No.
10 Q. Had you heard Perot Systems mentioned in
11 connection with any other of the strategies that
12 you described in your December 6th, December 8th
13 notes?
14 A. No.
15 Q. Had you heard Perot Systems mentioned in
16 any other context during the period that you
17 worked for Enron?
18 A. Not in connection with any Enron-related
19 matters.
20 Q. Do any of the questions that I have
21 asked you or the names that I have provided jog
22 your recollection of any of the traders that you
23 spoke to between the October meeting and the
24 November meeting?
25 A. No.

1 Q. Let's bring ourselves up to the November
2 meeting, then. If you can relate to us, again
3 to the best of your recollection, who attended.
4 A. Okay. The November meeting was held by
5 Richard Sanders and Gary Fergus. The purpose of
6 the meeting was to continue to respond to the
7 CPUC subpoena. There may have been other
8 subpoenas that had been -- that Enron had
9 received by that point. There may have been a
10 lawsuit filed by that point. At some point, the
11 class action lawsuit was filed in San Diego, and
12 Enron was one of the named parties.
13 By this time, at the second
14 meeting Mr. Yoder and I were at this point
15 referring to Mr. Fergus and Mr. Sanders as the
16 litigation team. That's the way we spoke of it
17 among ourselves: The litigation team is coming
18 back up to Portland.
19 At that meeting, I don't
20 remember who else was at the meeting besides Mr.
21 Fergus and Mr. Sanders. Mr. Fergus may have had
22 an associate or two with him from his law firm.
23 Q. Was Mr. Watkiss involved at that point?
24 A. I don't remember.
25 Q. Was anyone else that you can remember?

1 A. No.
2 Q. Did you meet with the traders on that
3 date?
4 A. The context for the second meeting was a
5 little bit different than the first one. The
6 second meeting Mr. Fergus and Mr. Sanders came
7 up to Portland, set up shop in the conference
8 room, and they were working on different things.
9 One of the things that they did was interview
10 traders. And in some of those interviews, I sat
11 in on those. They were also working on document
12 production issues, trying to determine where
13 documents were held, working out information
14 technology issues.
15 Q. So Mr. Fergus -- and you mentioned
16 another attorney whose name is --
17 A. Mr. Sanders.
18 Q. Mr. Fergus and Mr. Sanders conducted
19 separate interviews with the traders in the
20 November meeting?
21 A. Yes.
22 Q. Some of which you sat in on and some of
23 which you did not?
24 A. Yes.
25 Q. Do you recall the names of the traders

1 with whom they met without you being in
2 attendance?
3 A. If I understand the question you are
4 asking, meetings that I was not present at, who
5 was there?
6 Q. That you are aware of.
7 A. I'm not aware.
8 Q. Do you recall the traders who were
9 interviewed in your presence?
10 A. I recall John Forney and Jeff Richter
11 being there.
12 Q. Did you take notes of the November
13 meeting?
14 A. I don't remember if I did or I didn't.
15 Q. Do you know if anyone else took notes
16 of the November meeting?
17 A. I don't remember if anyone else did or
18 not.
19 Q. Was Ms. Hain at the November meeting?
20 A. I don't believe so.
21 Q. Did you see any memoranda or notes or
22 minutes circulated after the November meeting?
23 A. No.
24 Q. Did you have a draft of your December
25 6th memorandum by that point?

1 A. I may have.
2 Q. Do you recall when the first time was
3 that you would have circulated a draft of that
4 memorandum, if you circulated a draft of that
5 memorandum?
6 A. I was just going to say, as I thought
7 back through this, I clearly had a work in
8 progress at that point. What I don't remember
9 is if I shared the actual written product with
10 Mr. Fergus and Mr. Sanders at that point. We
11 definitely discussed the content of it and the
12 substance of it. And I also discussed the
13 substance and content with Mr. Yoder on a
14 regular basis.
15 Q. When you say "at that point," you mean
16 at the November meeting?
17 A. Yes, around the first week of November.
18 Q. Okay. Were you sharing your thoughts at
19 that time with anyone else at Stoel Rives?
20 A. Yes.
21 Q. Who would that be?
22 A. Marcus Wood.
23 Q. Okay.
24 A. And I may have mentioned the matter to
25 James Fell also.

1 Q. When would you recall having first
2 presented them with a draft, if ever?
3 A. In November, sometime later in the
4 month, I believe that was the first time that I
5 shared a draft with Marcus Wood.
6 Q. Okay. Again, in any course during the
7 November meeting, was any consensus reached or
8 decisions made with respect to how next to
9 proceed?
10 A. With respect to what?
11 Q. The work that you were conducting.
12 A. The memorandum -- I was preparing it, I
13 felt, for the benefit of the litigation team.
14 But the work assignment came from Mr. Yoder, not
15 from Mr. Fergus.
16 Q. Did Mr. Yoder give you any instructions
17 on or about the November meeting as to what to
18 do?
19 A. I think it was just an ongoing sense of
20 -- learn about these trading strategies and
21 incorporate that knowledge into a memorandum for
22 the benefit of the litigation team.
23 Q. So basically at that point your
24 instructions were to carry on?
25 A. Yes.

1 Q. Were there any decisions made with
2 respect to the Enron trading strategies
3 themselves? You indicated, for example, that at
4 the October meeting that there were instructions
5 issued with respect to the rounding incident.
6 Were there any similar decisions
7 or instructions made with respect to any of the
8 other trading strategies at the November meeting?
9 A. Could you rephrase the question?
10 Q. What, if anything, was decided with
11 respect to the trading strategies that had been
12 discussed?
13 A. I think the only conclusions that had
14 been drawn by that point were that the
15 strategies were complex; a lot more work by the
16 lawyers was needed to understand these
17 strategies. Certain of the strategies had
18 involved -- involved deceptive aspects.
19 Certainly at no time were the attorneys condoning
20 any of that. And the message from the attorneys
21 right from the beginning was, if you were doing
22 something that is illegal or something that is
23 deceptive, that wouldn't be permitted.
24 (Discussion off the record.)
25 A. Also at that meeting Mr. -- I recall

1 Mr. Sanders asking the traders during the
2 interviews: Are you still doing "X" strategy?
3 And I recall the traders generally saying no.
4 BY MR. CHABOT:
5 Q. You said from the outset that it was
6 the consensus of the attorneys that things deemed
7 illegal or deceptive ought not to be done; is
8 that correct?
9 A. Yes.
10 Q. When you mean from the outset, do you
11 mean from the October 4th meeting?
12 A. I think it would have always been the
13 attitude of the attorneys that illegal things
14 shouldn't be done.
15 Q. Had anybody expressed an opinion that
16 any of the activities were illegal?
17 A. No.
18 Q. Had anyone --
19 A. With the exception of the rounding
20 incident that I mentioned to you.
21 I should clarify, the rounding
22 strategy, nobody ever declared that it was
23 illegal. But it happened; they just said that
24 it should not continue. We were assured that it
25 had been an isolated incident, and they were

1 advised to return the money to the California
2 ISO.
3 Q. At or prior to the November meeting, had
4 any of the attorneys expressed the view that any
5 of the practices described were deceptive?
6 A. I don't recall.
7 Q. Had you reached any conclusions with
8 regard to whether any of the practices were, in
9 your opinion, illegal?
10 A. Well, I concluded that some of the
11 practices involved deceptive aspects to them. I
12 don't think I ever concluded that any of them
13 were illegal.
14 Q. I take it those were the views that you
15 expressed in the December 6th and December 8th
16 memoranda?
17 A. Yes.
18 Q. Did you have any views in that regard
19 that did not find their way into the December
20 6th or December 8th memoranda?
21 A. Any --
22 Q. Any further views that were not included
23 in those memoranda.
24 MR. HULKOWER: On anything?
25 Q. With respect to the legality or the

1 deceptive nature of the trading practices.
2 A. The purpose of my memorandum was to
3 describe and understand the trading strategies.
4 Q. Were you aware of any written direction
5 to the traders to discontinue these practices?
6 A. No.
7 Q. Were you aware of any written
8 communication back from the traders that the
9 practices had been discontinued?
10 A. No.
11 MR. MOORE: Could I have that
12 question back, please?
13 MR. CHABOT: Would you read the
14 question back for Mr. Moore.
15 (The question was read as
16 requested.)
17 BY MR. CHABOT:
18 Q. Were there any other meetings that were
19 held in connection with the CPUC subpoena and/or
20 your investigation of trading practices after
21 November and before your memorandum of December
22 6th?
23 A. First of all, just to clarify. You
24 said my investigation. I was not the compliance
25 person over there. I was not doing an internal

1 investigation. I was asked by in-house counsel
2 to understand the trading strategies and try to
3 describe them in the memorandum.
4 There was a meeting in December
5 -- I think it was the 10th and the 11th or the
6 11th and the 12th. That was after I had
7 delivered my memorandum.
8 Q. Was there anyone conducting what you
9 would consider to be an investigation at that
10 point, in that period?
11 A. During that same time period, Mr.
12 Fergus, as part of the litigation preparation,
13 was also trying to understand the trading
14 strategies. That was his purpose in coming up
15 -- one purpose in coming up to Portland and
16 interviewing traders on the 9th. I don't know
17 if what he was doing would be an investigation
18 as you understand the word to be. Other than
19 that, no.
20 Q. With respect to the interviews with the
21 traders -- and these would be both the group
22 discussions as well as your individual
23 interviews, as well as the interviews in which
24 you sat in on -- do you recall if any of the
25 traders at any time mentioned the involvement of

1 Puget Sound in any of the trading practices?
2 A. First, just to be clear. You keep
3 saying with respect to me interviewing the
4 traders. I don't know if you would call my
5 discussions with them interviews. They were very
6 informal. On a certain day if I were working
7 on the memorandum I had a question, I would walk
8 out to the trading floor and ask a certain
9 person: Do you have a few minutes? I'm
10 struggling to understand this issue here. Do
11 you have a few minutes to talk about this? And
12 we might talk about it, and then I would go
13 back and work on the memorandum.
14 So I would just call those
15 discussions. They were not formal interviews with
16 a court reporter or me asking the questions.
17 Q. I appreciate the clarification.
18 A. I forgot your question.
19 Q. The question was whether Puget Sound
20 Energy ever came up as one of the participants
21 in the trading strategies.
22 A. I'm aware that Puget is in my
23 memorandum. I believe that that was from a
24 comment that was made at the October 3rd
25 meeting. I don't remember who made it and I

don't remember the context. But in my memorandum, I think it mentioned Puget Sound.

Q. Again, it's fair to say that you don't recall the details; you are familiar with that entity having been named, but you can't recall any of the details?

A. Yes.

Q. What about Powerex?

A. Likewise, the same answer.

Q. PG&E?

A. I don't recall any questions about Portland General, or anything about Portland General.

Q. Arizona Public Service?

A. Yes. I think it was the firm/non-firm strategy that involved APS, in that APS had sold some energy to Enron as non-firm, and then it had been sold to a California ISO as a firm. And APS had reported that to the ISO.

Q. In fact, on the page that you mention APS in your memo, which is AB 7, right above the reference to APS, you have a section that the traders claim that, quote: "Everybody does this, especially for imports from the Pacific Northwest and California." And that is, in

1 fact, under Item 8, selling non-firm energy as
2 firm energy.
3 Sitting here today, do you have
4 any recollection of who the "everybody" is that
5 is referred to, or who was included among the
6 "everybody" that you referred to there?
7 A. I don't. This would have been a
8 comment that it's a trader saying: Everybody
9 does it. It's okay. There is no problem with
10 this strategy. Everybody does this.
11 Q. Do you recall that coming from any
12 specific trader, or is it fair to say that it
13 was a general conclusion?
14 A. I don't recall a specific person saying
15 that.
16 Q. What about the information with respect
17 to Arizona Public Service, do you recall that
18 coming from a specific individual?
19 A. I think that may have been John Forney.
20 Q. Similarly, back on page 3 of that
21 memorandum, AB 3, under the major heading B,
22 "Representative Trading Strategies," there is a
23 statement there that specifically references Fat
24 Boy, but it says: "In some cases, i.e., Fat
25 Boy, Enron's traders have used these nicknames

1 with traders from other companies to identify
2 these strategies."
3 Once again, do you recall what,
4 if any, other companies were referenced in that
5 regard?
6 A. I don't. The basis for that statement
7 was that -- I think it was the October 3rd
8 meeting, one of the attorneys asked the traders:
9 You know, are these names -- does everybody use
10 these strategies? Are others familiar with the
11 names? Have you ever told anybody outside the
12 company of these names? And at least one person
13 had said that, yes, they had used the name with
14 somebody else.
15 Q. But sitting here today, that's as
16 specific as you recall?
17 A. Yes.
18 Q. Again, on the previous page 2, AB 2,
19 there are two references there. In the last
20 full paragraph, it begins with: "Two other
21 points bear mentioning. First -- " I inserted
22 the "first" -- "Although Enron may have been the
23 first to use this strategy, others have picked
24 up on it, too." And that appears to be a
25 reference to the inc-ing practice.

1 MR. HULKOWER: I'm sorry, Phil,
2 is there a question?
3 BY MR. CHABOT:
4 Q. First off, let me make it clear, that
5 because it falls under the inc-ing discussion,
6 that the reference there is to inc-ing?
7 A. Yes.
8 Q. Do you recall who the "others" refers
9 to?
10 A. No.
11 Q. Okay.
12 A. If you keep reading, it says that others
13 were using it. This can be shown by looking at
14 the ISOs' aggregate supply data.
15 Q. Right. That information comes from
16 someone who told you that, according to that
17 sentence. Do you recall who either said to you
18 that others have picked up on this practice or
19 than the information can be obtained from the
20 ISO real time metering?
21 A. Again, I believe that may have been John
22 Forney.
23 Q. In the following sentence, it says:
24 "Second, Enron has performed this service for
25 certain other customers."

1 Do you recall who those other
2 customers were?
3 A. I don't recall that it was anybody
4 besides -- or that I had been told at that time
5 anybody besides Powerex or Puget Sound, which is
6 listed right there.
7 Q. Have you acquired any additional
8 information about that practice since?
9 A. No.
10 Q. Do you recall from whom that information
11 was acquired?
12 A. I don't.
13 Q. We can go through each of the practices
14 individually if need be, but let me see if I
15 can ask the question in a general context first.
16 Were the practices that you
17 described in your December 6th and December 8th
18 memos recurring practices, or more like the
19 Silver Peak incident, which was a one-time
20 incident?
21 MR. MOORE: Can I have that
22 question back, please.
23 (The question was read as
24 requested.)
25 A. It's hard to generalize. And it's

1 probably better for us to go one by one.
2 BY MR. CHABOT:
3 Q. Okay. Let's do that.
4 A. But I was going to say, generally, most
5 of these were of a recurring type, at least up
6 until the point when I first was thinking about
7 them.
8 Q. Since you suggested that we go this
9 route, let's go down and take each and every one
10 of them. Let's start off with the inc-ing
11 practice.
12 MR. HULKOWER: Phil, before we
13 do that, let's take a five-minute break.
14 MR. CHABOT: Sure. We're going
15 to go off the record here and take a break for
16 five minutes.
17 (A short break was taken.)
18 MR. CHABOT: Let's go back on
19 the record.
20 BY MR. CHABOT:
21 Q. We're going to pick up with each of the
22 practices outlined in the December 6th and
23 December 8th memos.
24 Let me get one question out of
25 the way.

1 Can you shed light on why there
2 are two apparently identical memos bearing
3 different dates?
4 A. I'm not certain. I think it's just
5 that there is an automatic updating function in
6 the document. I think that the -- the one that
7 I did was December 6th. I think that some of
8 the documents that I was -- or that I e-mailed
9 to Enron were printed out on the 8th. That's
10 the date that you see.
11 Q. Thank you, Mr. Gates.
12 With that explanation -- and I
13 think it makes sense to me -- let's go on.
14 Let's start with the inc-ing.
15 The question that I have is
16 whether it's your understanding that this was a
17 single event or a repeated practice.
18 A. Inc-ing load was a repeated practice.
19 Q. At any time in your discussions or
20 conversations with others, did you come to learn
21 who it was at Enron that had conceived of or
22 invented this practice?
23 A. Not that I recall.
24 Q. Do you recall any particular traders who
25 engaged in the practice?

1 A. I do. And just anticipating a similar
2 question for each one of these, a helpful way to
3 think of this is actually in terms of the desk
4 that would have used the strategy. So this
5 strategy, for example, the inc-ing load, my
6 understanding is that generally it's a day-ahead
7 or a short-term strategy, which would have been
8 the short-term California desk, and that was Jeff
9 Richter.
10 Q. Okay. If you could, then, just to
11 expedite the record, basically I'm after the same
12 information with respect to each one of these
13 practices, whether it was a single event or a
14 repeated practice, if you have any information as
15 to who originated the concept and which of the
16 traders or trading desks engaged in the practice.
17 A. All right.
18 Q. I believe the next one -- you have a
19 "Relieving Congestion" heading which corresponds
20 to the inc-ing heading, but is that really a
21 separate --
22 A. To give you some context here, when I
23 originally started the memo, I had my list of
24 all of these strategies and just started trying
25 to explain each one. And then it occurred to me

1 sometime closer to before I finalized the
2 memorandum that actually there was a bigger
3 picture here, and that really all of these
4 strategies could be categorized into either some
5 variation on inc-ing or some variation on
6 congestion trading. That's why at the beginning
7 it says that there are two big groups. And
8 then the second part, or part B of the
9 memorandum, then goes through the applications of
10 those two general concepts.
11 Q. Okay. So --
12 A. So No. 2, as you pointed out, is just
13 kind of a general statement about congestion
14 trading. But the applications of it are listed
15 below.
16 Q. Under B?
17 A. Under B.
18 MR. HULKOWER: In other words,
19 if we go through the Bs, 1B1, B2, that will
20 cover the various strategies that are listed in
21 here.
22 BY MR. CHABOT:
23 Q. What we're reading here is a subset of
24 the Relieving Congestion strategies?
25 MR. HULKOWER: And the inc-ing.

1 A. And the inc-ing.
2 BY MR. CHABOT:
3 Q. I think that's probably where the
4 confusion comes in.
5 So there is nothing specific
6 under two. We go to B1 for the export of
7 California power.
8 A. Okay. My understanding was that that
9 was -- had been a strategy that had occurred on
10 more than one occasion, and that would have been
11 the strategy employed by both the real time desk
12 and the day-ahead desk.
13 Q. And Mr. Richter was at the day-ahead
14 desk?
15 A. Yes.
16 Q. Who would be on the real time desk?
17 A. On the real time desk, there were a
18 group of 10 to 15 traders who rotated different
19 shifts. The real time desk is a 24/7 desk, so
20 there were rotating schedules, and sometimes
21 people would be working the night shift,
22 sometimes the day shift.
23 Q. Was there a person in charge of that
24 desk?
25 A. Yes. John Forney.

1 Q. And again, the one element you might
2 have left out is whether you have any
3 recollection as to who the father of the thought
4 is.
5 A. Energy has been exported from of
6 California and into California for 50 years.
7 It's nobody at Enron who invented that.
8 Q. No. 2, then, the non-firm export
9 practice.
10 A. I don't know who initiated this
11 practice. This one -- this practice was
12 discontinued by the time it was first explained
13 to me. It had probably happened more than once.
14 But I don't know that one way or the other. And
15 it was something that the ISO internally had
16 discovered this and posted a notice on its
17 website saying that certain market participants
18 had been engaged in this practice, and for them
19 to cut it out.
20 Q. Okay. Do you recall which desk would
21 have been engaged?
22 A. I don't.
23 Q. Then as I did once in a speech, No. 2
24 again.
25 A. Also just to point out, there are two

1 No. 2s here.
2 Death Star -- I don't know who
3 started that strategy. And I believe it
4 happened on more than one occasion. And this
5 would have been something I think only the real
6 time desk would have done.
7 Q. No. 3, load shift?
8 A. I believe this strategy occurred on more
9 than one occasion. This would have been both
10 desks, I believe, both real time and California
11 day-ahead. And I don't know who initiated this
12 strategy.
13 Q. No. 4, Get Shorty?
14 A. I'm not sure who initiated this
15 strategy. I believe it occurred more than once.
16 And I think it's possible this could have been
17 done by either desk.
18 Q. Okay. No. 5, Wheel Out?
19 A. I don't have any independent memory of
20 whether this was isolated or it happened on more
21 than one occasion. And I think it's more likely
22 that this would have been done by the real time
23 desk, but it's possible it could have been the
24 day-ahead desk also.
25 Q. Does the fact that you say this strategy

1 was used when suggests, subject to reasonable
2 interpretation, that it was done more than once?
3 A. I wouldn't read too much into the tense
4 there. It's possible it was done more than once.
5 Q. Fat Boy, No. 6.
6 A. Fat Boy is the same thing as inc-ing
7 load.
8 Q. So your responses to the questions would
9 be the same?
10 A. Yes.
11 Q. Item No. 7, Ricochet?
12 A. I don't know who initiated this
13 strategy. It was done on more than one
14 occasion. And I suppose it could have been done
15 by either the day-ahead desk or the real time
16 desk.
17 Q. Item No. 8, Selling Non-Firm Energy as
18 Firm Energy.
19 A. My understanding was that this issue
20 came up -- or that this was -- it happened on
21 more than one occasion. I think this could have
22 been either desk. And I don't know who initiated
23 this strategy.
24 Q. Item No. 7 (sic), Scheduling Energy to
25 Collect Congestion Charges?

1 A. I don't know who initiated this
2 strategy. My understanding is that it was done
3 more than once. And I suppose you could do
4 this by -- or either desk could have done this.
5 Q. In connection with any of these
6 strategies, and I suggested some other entities,
7 I wonder if you had any further recollection on
8 any of the other either generators, utilities,
9 power marketers that you became aware of engaged
10 in the same or similar practices.
11 A. Other than what we have all read in the
12 newspapers over the past couple of months, no.
13 Q. No direct knowledge based upon your
14 discussions in the end of the 2000 time period?
15 A. That's correct.
16 Q. Specifically, do you recall any
17 discussions having to do with Los Angeles
18 Department of Water and Power?
19 A. No.
20 Q. Any discussions with regard to the city
21 of Redding, California?
22 A. No.
23 Q. Or the Northern California Power Agency?
24 A. No.
25 Q. Did Ms. Hain participate with you in any

1 of the discussions that you had with the
2 traders?
3 A. No.
4 Q. Although she did attend at least the
5 October group meeting, correct?
6 A. Yes.
7 Q. Do you recall any other meetings that
8 she attended?
9 A. No.
10 Q. Could you provide a description of what
11 her role was on the Enron trading floor.
12 A. Yes. Mary Hain was a regulatory
13 attorney, and she answered questions about the
14 tariffs. She assisted in the preparation of
15 briefs to file with FERC, Federal Energy
16 Regulatory Commission, F-E-R-C. And she probably
17 helped develop policies -- I guess just the
18 standard things that most regulatory in-house
19 lawyers do.
20 Q. Would it be a fair characterization of
21 her job that one of her responsibilities was to
22 respond to inquiries from the traders from time
23 to time?
24 A. Yes.
25 Q. Do you have any knowledge as to what,

1 if any, role she played with respect to each of
2 the strategies identified in your December 6th
3 memo?
4 A. I'm not aware of any relationship
5 between her and the strategies.
6 Q. Are you aware of any communications that
7 she might have had with traders with respect to
8 any of those strategies?
9 A. No.
10 Q. Would it have been the practice within
11 Enron for any such communications between the
12 traders and Ms. Hain to have been memorialized
13 in writing?
14 A. I don't know.
15 Q. So you don't recall having seen any
16 memoranda along the lines of a memo to file from
17 Mary Hain, an inquiry from Mr. Forney?
18 A. I don't recall any kind of -- ever
19 seeing or being aware of any memoranda between
20 traders and Mary Hain regarding the strategies.
21 Q. Okay.
22 (Discussion off the record.)
23 BY MR. CHABOT:
24 Q. I'd like to ask you next to take a look
25 at the AA section of the Volume 1 exhibit, your

1 Exhibit 2. It's going to take some time to do
2 this. But if you could identify whether any of
3 the notes that are included in this section are
4 things that you have written, and if you can
5 identify any of the handwriting in the event
6 that those are not your notes.
7 MR. CHABOT: We're going to be
8 taking some time here, I suspect, so let's go
9 off the record. We're off the record.
10 (Discussion off the record.)
11 MR. CHABOT: While we were off
12 the record, the witness has gone through Exhibit
13 No. 2, the tab marked AB, and he is prepared to
14 identify either any documents that contain his
15 notes, or to the extent he can, identify the
16 handwriting with those documents that he can
17 identify.
18 A. Okay. Starting at document -- just for
19 convenience, I'm going to say 1 to -- starting
20 on page 1 there are notes. Starting on 2 that
21 go through page 6 -- as Bate-stamped -- and
22 these are not my notes. And at this time, I do
23 not recognize them.
24 BY MR. CHABOT:
25 Q. Okay.

A. On page 7, these appear to be the notes that have been represented to me as being Mary Hain's notes. I don't know that they are Mary Hain's notes.

Q. Who was it that suggested to you that they were?

A. I think it was Senator Barbara Boxer.

Q. That's a high source, but I'm not sure if it's authoritative. It's a high source.

A. Moving through those notes, page 10, page 11, page 12, page 13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24, 25, 26, 27 -- I'm not sure if those were the same group of notes, or if these were from different days. Again, I don't recognize them.

Page 28, 29, 30, 31, 32, 33, 34, 35. Let me skip ahead and I'll just summarize a chunk.

The handwritten notes end on page 40, and they are not my notes.

Q. I take it also you do not know whose they are?

A. I have no personal knowledge of whose they are.

Q. Has it been suggested to you by anyone

1 whose they might be?
2 A. Other than Barbara Boxer's suggestion on
3 May 15th of this year -- which also was the
4 first time that I had ever seen these notes --
5 no.
6 Q. Okay.
7 A. Looking at page 41, this is a memorandum
8 dated 9-29-2000.
9 MR. HULKOWER: Do you want him
10 to discuss the notes? You asked about the
11 notes, I thought. Should we just skip over
12 those?
13 BY MR. CHABOT:
14 Q. If you have a comment, it would probably
15 expedite things if you do have a comment you
16 would like to make.
17 A. This is from Mike Day. It wasn't sent
18 to me. I don't remember seeing this e-mail.
19 Page 42, this is a short
20 memorandum that I prepared following the receipt
21 of the subpoena from the CPUC. This was -- I
22 think ultimately what this was -- I prepared
23 this for Tim Belden, and the purpose of this was
24 to write something up that could be distributed
25 to the employees on the trading floor to let

1 them understand about the -- responding to the
2 subpoena.
3 Q. This memorandum is undated.
4 Do you recall when it was
5 written?
6 A. I don't have any firsthand knowledge.
7 Maybe it's possible from the context of it to --
8 Q. There is a reference to October 4th,
9 which seems to be the earliest date in here.
10 A. It must be before October 5th, because
11 at the bottom of it it says: "We have obtained
12 an extension from the CPUC. Under the terms of
13 the extension we must send a letter to the CPUC
14 by October 5th of 2000."
15 So I assume this was written
16 before that.
17 Q. Okay.
18 A. Page 44 is an e-mail that seems to be
19 discussing the response to the CPUC subpoena
20 again. I may have been forwarded a copy of
21 this. I don't remember now, though, whether I
22 saw it or not.
23 Q. I take it you don't know whose notes
24 those are in the margins?
25 A. No.

The next page with something on it is page 49. There are some handwritten notes there. They are basically illegible, but what I can read, I don't recognize.

Q. Your talking about AA, a series of zeros, 49.

A. Documents 50 through 56 are all handwritten notes. I don't recognize them.

Q. On page 54, AA 54, right at the top, after it says, "fax to Mary Hain," there is a word which could be "from." And then there is the name "Greg" and the bottom half of some letters.

Does that suggest anybody to you?

A. Perhaps Greg Wolf. But it doesn't look like it has enough letters.

Q. Okay.

A. I don't recognize the e-mail on pages 57 or 58. I don't recognize the documents on 59 through 62. I don't recognize any of the documents Bate-stamped 64 through 67.

Q. You said you do not?

A. I do not.

Documents 69 through 100, I'm

1 not familiar with any of those documents.
2 Q. Okay.
3 A. Documents 101 through 148, I do not
4 recognize.
5 Documents 149 through 177, I
6 don't recognize any of those documents, either.
7 Starting at AA 0000178, these
8 appear to be billing invoices from Stoel Rives
9 to Enron, and these billing sheets reflect work
10 that was done by Stoel Rives' attorneys for
11 Enron.
12 Q. Okay.
13 A. And that takes us up to the end.
14 Q. Okay. Thank you.
15 (Discussion off the record.)
16 BY MR. CHABOT:
17 Q. I'm next going to ask you to take a
18 look at some specific documents in Volume 2.
19 These bear two Bates numbers. There is an EC
20 designation, which was, I believe, the
21 designation that has been attached to them by
22 the senate committee, Senator Dunn's committee in
23 California. And then an AD designation, which
24 is our internal numbering system on the left.
25 If you can take a look at AD

1 3.
2 A. Okay.
3 Q. At the top of that page there is a
4 reference to "Forney perpetual loop."
5 My first question to you is,
6 have you ever seen this document before?
7 A. Yes.
8 Q. When was the first time that you recall
9 having seen this?
10 A. I first saw this a couple of weeks ago
11 in the context of a different deposition.
12 Q. The term "perpetual loop," or "Forney's
13 perpetual loop," was that something with which
14 you had become familiar during the period prior
15 to the December 6th memo?
16 A. I had never heard that term before.
17 Q. Okay.
18 A. Just to clarify. I may not have seen
19 the document, but I may have just heard the term
20 in the context of the deposition.
21 Q. Okay. The next is page AD with a
22 series of zeros, the last digit being 5. This
23 is a May 5, 2000, memorandum from Michael
24 Driscoll. It's on the subject of: Final
25 procedures for Death Star.

1 Had you ever seen this memo?
2 A. No.
3 Q. Had you seen memos similar to this?
4 A. No.
5 Q. Did you have any understanding with
6 respect to the practices that would be involved
7 by the traders at Enron in order to implement
8 any of the strategies identified in your memo of
9 December 6th? By "the practices," I mean
10 documentary steps that would have to be taken to
11 execute any of those strategies.
12 MR. HULKOWER: I didn't
13 understand this.
14 Q. This appears to be a memo communicating
15 procedures to implement at least one incidence of
16 Death Star?
17 A. Right.
18 Q. Prior to the time that you wrote your
19 December 6th memo, were you aware that in order
20 to implement one or any of those strategies, a
21 document such as this, or a similar document,
22 would have been generated?
23 A. I wasn't aware that documents -- or that
24 this document had been generated.
25 I'm not sure I follow your

1 question.
2 Q. What about similar documents implementing
3 an inc-ing practice or a Fat Boy episode or
4 anything of that nature?
5 A. I don't know. Documents may have been
6 created -- this type of e-mail to me, if you
7 took out Death Star and all those other things,
8 seems fairly unremarkable.
9 Q. What I'm trying to get at is, during
10 the course of discussions that you were having
11 with traders, did you become aware that documents
12 such as this existed?
13 A. No.
14 Q. The next document would be AD 11. This
15 document specifically refers to Black Widow.
16 I take it from your previous
17 answer that you had not seen this previously?
18 A. No.
19 Q. Had you seen it before today?
20 A. No. Maybe I spoke too -- no, I don't
21 believe that I saw this before.
22 Q. Okay. AD 14, this is a document that
23 refers to Red Congo. It also gives reference to
24 Redding, which I asked you about earlier.
25 Had you seen this document

1 before?
2 A. No.
3 Q. There are two other entities identified
4 here, Pacific Corp and WAPA, or the Western Area
5 Power Administration.
6 Do you recall any discussions,
7 prior to the preparation of your memo of
8 December 6th, in which Pacific Corp or WAPA was
9 referenced with respect to any of the trading
10 practices that you described in your memo?
11 A. Pacific Corp may have been referenced
12 with respect to the Ricochet strategy.
13 Q. If that were the case, from whom would
14 it be most likely that you would have heard
15 that?
16 A. Either someone on the real time or the
17 short-term California desk.
18 Q. But you have no more detailed
19 recollection?
20 A. No.
21 Q. I would like you to refer to a batch of
22 documents beginning on page AD 106 through AD
23 147.
24 A. Okay. Do you want me to just look
25 through those?

1 Q. If you could briefly. I think you will
2 see very quickly what they relate to.
3 MR. ARD: This is Mr. Ard. Do
4 you have a Bates number that starts with EC for
5 those documents?
6 MR. CHABOT: Yes. This batch
7 is EC 784. The last three digits is 784.
8 (Discussion off the record.)
9 MR. HULKOWER: We're up to what
10 number?
11 MR. CHABOT: I believe the last
12 in this batch would be 147, the corresponding EC
13 numbers 825.
14 (Discussion off the record.)
15 MR. HULKOWER: Did you say up
16 to 149?
17 MR. CHABOT: 147, I think. 149
18 begins the --
19 A. I'll stop at 147.
20 I'm not familiar with these
21 documents.
22 BY MR. CHABOT:
23 Q. Okay. You had not seen them before
24 today?
25 A. No.

1 Q. Okay. Going back to the sequence of
2 events, then, leading up to your December 6th
3 memorandum, do you recall any meetings after the
4 November meeting, the early November meeting, but
5 before the December 6th memo?
6 A. Not specifically. There may have been.
7 Q. Is it fair to say, though, however, that
8 during this period you would have likely to have
9 been continuing your conversations and discussions
10 with traders?
11 A. Yes. Also during that time I was
12 working on many other commercial matters for
13 Enron as well as working for other clients
14 besides Enron.
15 Q. Okay. As I understand your testimony
16 that you gave before the senate -- or I might
17 have drawn this from some other sources -- but
18 there came a time when you showed Mr. Yoder a
19 copy of your December 6th memorandum?
20 A. Through the process of developing the
21 memorandum, Mr. Yoder and I had several
22 conversations about the trading strategies.
23 Q. Again, to the extent that you can be
24 specific, I would appreciate it if you would try
25 to be -- but I wouldn't expect you to remember

1 dates necessarily or the number of incidents --
2 but if you could again, as specific as you can
3 be, reflect what took place during those
4 conversations.
5 A. Certainly. Mr. Yoder and I had a very
6 good working relationship. We would talk
7 frequently during the day, sometimes a couple of
8 minutes at a time, sometimes longer. We worked
9 on many different matters. His primary
10 responsibility was to negotiate energy master
11 trading contracts. So I had plenty of
12 opportunity to talk to him informally about all
13 the different issues that we were working on.
14 With respect to the trading
15 strategies, we had several meetings or
16 discussions, whatever you want to call them,
17 about the trading strategies, generally in his
18 office. He had a white erasable board there,
19 and we would sit there and draw pictures of
20 California and draw arrows and try to figure
21 things out and explain it to each other and kind
22 of test our understanding back and forth. It
23 was a collaborative process in that sense.
24 Q. Okay. So he was aware that a
25 memorandum was in the process of being drafted?

1 A. He had asked me to prepare the
2 memorandum.
3 Q. Did you share drafts with him along the
4 way?
5 A. I'm almost certain that I did. I don't
6 recall the exact dates. But probably at least
7 by mid November I probably would have showed
8 something to him.
9 Q. Was he an active participant in the
10 drafting process?
11 A. Not in the drafting, but in the
12 understanding process.
13 Q. Did you share drafts with any others?
14 A. I remember showing at least a portion of
15 the draft to John Forney and asking him to help
16 me explain, or to kind of check my math, as it
17 were, on the inc-ing load strategy.
18 Q. Okay. Do you recall what Mr. Forney's
19 comments were?
20 A. I think he just helped me get some of
21 the technical aspects right.
22 Q. So again, I'm just trying to get this
23 straight. You had the early November meeting and
24 continued your discussions and preparation of the
25 drafts?

1 A. Right.
2 Q. And then the memorandum was released on
3 December 6th?
4 A. Yes. I think it's important also to
5 note that I met with Marcus Wood at least a
6 couple of times. He was my supervising partner
7 for this account. Mr. Wood and I had a couple
8 of discussions. I shared a draft with Mr. Wood,
9 and Mr. Wood took the draft and made some
10 revisions to it. And then that finalized
11 version was what was ultimately delivered to the
12 client.
13 Q. I'm glad you brought that up, because
14 there have been two things of some interest with
15 respect to the December 6th memo, and that is
16 the fact that Mr. Wood's name is not on it.
17 I am wondering if you can shed
18 any light on that.
19 A. I don't think it was -- when I started
20 the memorandum, it was originally from Stephen
21 Hall to Christian Yoder. It was a small
22 project. As the memorandum developed and our
23 understanding developed, Christian Yoder asked
24 that his name be added to the memorandum. He
25 shared my concerns about certain of the deceptive

1 aspects of the trading strategies and wanted to
2 make sure that it was brought to management's
3 attention.
4 So the focus of the memorandum
5 was changed from being something to him to help
6 him and the legal team understand things to
7 being something that was written to Richard
8 Sanders. And then Mr. Yoder passed it to upper
9 management.
10 Q. That is the other side of the question,
11 why Mr. Yoder's name appears on a Stoel Rives
12 memo.
13 A. Right. Did I explain that?
14 Q. Yes. It was an outcome of the drafting
15 process?
16 A. Yes. In retrospect, it seems kind of
17 unusual. But it made sense at the time.
18 Q. Was there anyone who asked that they be
19 added to it as an author?
20 A. No.
21 Q. Was there anyone who asked that they not
22 be included as an author?
23 A. No.
24 Q. What occurred after this was presented
25 to Mr. Sanders?

1 A. My memory is that on December 6th, I
2 e-mailed the memorandum to Mr. Fergus, Mr.
3 Sanders, Mr. Yoder and to Elizabeth Sager. Then
4 the next day Mr. Wood and I met with Mr. Yoder
5 and walked through the memorandum, and Mr. Wood
6 advised Mr. Yoder on certain aspects.
7 Q. Who is Elizabeth Sager?
8 A. Elizabeth Sager was Vice President and
9 Assistant General Counsel of Enron North America.
10 She was Christian Yoder's boss. She was a power
11 trading attorney. She was responsible for making
12 sure that master agreements were negotiated. She
13 supervised that process.
14 Q. Do you recall when that walk-through
15 meeting would have occurred?
16 A. December 7th, the next day.
17 Q. What then occurred?
18 A. Mr. Wood and I met with Mr. Yoder. Mr.
19 Wood talked about the different strategies. At
20 that meeting I remember that he brought along
21 copies of California criminal statutes, and he
22 discussed those with Mr. Yoder. And I guess
23 that's about it.
24 Q. What, if anything, was your involvement
25 with respect to the subject matter of your

1 memorandum after December 7th?
2 A. That was pretty much the end of this
3 project, or assignment. However, the following
4 week, Monday or Tuesday, there was another
5 meeting of the litigation team up in Portland.
6 And at that meeting, I went there, and there was
7 a larger group at that time of more attorneys in
8 addition to the Brobeck firm. There may have
9 been some experts there. I'm not sure. But
10 there may have been 10 people.
11 At that time I walked through
12 the memorandum and explained the trading
13 strategies, and probably also gave a basic
14 discussion about how the California energy market
15 works to the litigation team.
16 But by that point -- well, I
17 guess that answers your question.
18 Q. Do you recall anyone having made notes
19 of that meeting?
20 A. I don't recall one way or the other.
21 Q. Do you recall any after-meeting memoranda
22 or minutes?
23 A. No.
24 Q. Did anything further occur with respect
25 to the subject addressed in your memoranda after

1 that meeting?
2 A. My understanding is that Richard Sanders
3 advised the traders that if any of these
4 practices were still continuing, that they were
5 to stop them.
6 Q. How do you come by that understanding?
7 A. Well, Mr. Sanders testified to that in
8 the senate, and I may have been aware of that
9 at the time. At this point in time, I don't
10 remember --
11 MR. MOORE: I'm sorry. I can't
12 hear.
13 Would you read that back for
14 me.
15 (The answer was read as
16 requested.)
17 A. I don't remember if I knew that or not.
18 BY MR. CHABOT:
19 Q. So as we say, you have no independent
20 recollection of that fact?
21 A. That would be a shorter way of saying
22 it.
23 Q. So again, you never saw any written
24 instructions to discontinue the practices, and
25 conversely no written acknowledgement that the

1 practices had been discontinued?
2 A. From Mr. Sanders, was that your
3 question?
4 Q. From anyone.
5 A. I didn't see any written instructions,
6 no.
7 Q. Did you ever learn that Enron traders
8 were actively observing other entities in the
9 market engaged in these practices, similar
10 practices?
11 MR. HULKOWER: Actively
12 observing other entities --
13 Q. From watching market data, whether the
14 traders came to the conclusion that there were
15 other entities that could be observed by Enron
16 as engaging in these practices.
17 MR. HULKOWER: Other than the
18 reference in the memo that you discussed?
19 MR. CHABOT: Right.
20 A. Other than the inc-ing load, no.
21 BY MR. CHABOT:
22 Q. Okay. Apart from the traders, who you
23 have identified, did you ever become aware of
24 any other individuals within Enron who were aware
25 of the practices described in your December 6th

1 memo prior to December 6th?
2 A. Other traders on the real time desk that
3 I haven't mentioned may have been aware of
4 these. And I would be hard-pressed to recall
5 their names right now. But I am sure you could
6 get that through an organizational chart or some
7 other means.
8 Q. What I'm trying to get at is whether
9 you are aware of anyone else at Enron who was
10 aware of it.
11 MR. HULKOWER: Non-traders?
12 A. Besides the traders?
13 BY MR. CHABOT:
14 Q. Yes.
15 A. No.
16 Q. Did you acquire any information about
17 the knowledge of others besides traders after
18 your December 6th memo?
19 A. I'm sorry, repeat that.
20 Q. Did you learn whether anyone besides
21 traders were aware prior to December 6th, but
22 you became aware of the fact that they knew
23 after December 6th?
24 A. No.
25 Q. I know that you have testified before

1 the senate. You mentioned earlier that you have
2 given other depositions.
3 Could you identify the entities
4 before whom you have given depositions in
5 connection with this matter.
6 A. The Commodities Futures Trading
7 Commission and the FERC. That was a joint
8 deposition.
9 Q. Are there others for whom you are
10 scheduled to give depositions?
11 A. No. This is the last one. There was
12 another deposition that I did with the attorneys
13 general from California, Washington and Oregon.
14 Q. That was before the Three-State Task
15 Force?
16 A. If that's what they call themselves.
17 MR. HULKOWER: They didn't use
18 that name when we met with them.
19 MR. CHABOT: Okay.
20 I'm going to suggest that we
21 take another five-minute break here so I can go
22 over my notes. We may be able to wrap up
23 shortly.
24 (Discussion off the record.)
25 (A short break was taken.)

1 MR. CHABOT: We're back on the
2 record.
3 BY MR. CHABOT:
4 Q. Out of a desire to avoid carrying more
5 documents than need be, I did not bring with me
6 multiple copies of your testimony before the
7 senate.
8 Have you had a chance to review
9 your testimony?
10 A. Not closely. I'm familiar with it.
11 Q. Again, without making it an exhibit to
12 this, I'm going to ask you a question as to
13 whether or not the transcript accurately reflects
14 --
15 MR. ARD: This is Mr. Ard.
16 You are dropping off. I'm not sure what you
17 are asking him about.
18 MR. CHABOT: I'm working around
19 to it.
20 BY MR. CHABOT:
21 Q. I'm going to ask you a question as to
22 whether you would supplement the record with any
23 changes or corrections that you have or would
24 like to make to your testimony before the senate
25 so that I don't have to ask you specific

1 questions about your answers before the senate.
2 MR. MOORE: I lost that last
3 part again. What testimony are you asking him
4 about?
5 MR. HULKOWER: The question is,
6 does he stand by his senate testimony? In
7 fairness, I'm not going to let him answer that.
8 He doesn't recall specifically his testimony. It
9 covered a lot of things. We can't even speak to
10 the accuracy of the transcription. I think
11 there may have been a statement made by one of
12 the other participants attributed to Steve.
13 MR. CHABOT: Actually, that's
14 what I'm trying to get at.
15 BY MR. CHABOT:
16 Q. The procedure that we could work out is
17 that if you do have any changes that you would
18 make to that testimony, if you would let us know
19 what it is.
20 MR. HULKOWER: We'll take a
21 look at it. And if there is anything that
22 stands out as material --
23 THE WITNESS: If we supplement
24 the record, I'll give him a copy.
25 MR. CHABOT: That's the way

1 we'll do it. Yes. That's fine. That works for
2 us.
3 BY MR. CHABOT:
4 Q. Did you ever become aware that Gary
5 Fergus was requested to conduct a similar set of
6 interviews or discussions with PG&E traders?
7 A. No.
8 MR. CHABOT: Those are all the
9 questions I have.
10 Does anyone have any cross on
11 the phone?
12 MR. MOORE: I do have a few
13 questions. But considering my position in this
14 docket, I will do the cleanup. If anybody else
15 has any questions, I would prefer to wait until
16 they ask those and get the answers first.
17 MR. CHABOT: Does anybody else
18 have any other questions besides Mr. Moore?
19 MR. MOVISH: I do not.
20 MR. MELVIN: This is Dennis
21 Melvin. We have no questions.
22 MR. HULKOWER: We're on cleanup.
23 EXAMINATION
24 BY MR. MOORE:
25 Q. Mr. Hall, for the record, my name is

1 Charlie Moore. I'm with the law firm of
2 Labouef, Lamb. And in this matter I represent
3 Enron Power Marketing.
4 First of all, have you and I
5 ever met before?
6 A. Not that I'm aware of.
7 Q. Second of all, have you and I ever
8 spoken at any time in the past at all?
9 A. Not that I recall.
10 Q. Have you had any conversations or
11 communications with anybody in my law firm of
12 Labouef, Lamb about this matter?
13 A. Not about this matter. But I worked
14 with Labouef, Lamb on several matters when I was
15 working at Enron.
16 Q. What I'm particularly interested in is
17 whether or not the subject matter of your
18 testimony today has been discussed by you with
19 any member of my law firm or anybody that you
20 know I'm connected with in connection with this
21 case.
22 A. It has not.
23 Q. So would you agree with me that -- my
24 questions to you today are pretty much on a cold
25 basis, in the sense that you and I have never

1 had any conversations and there has been no
2 communications of any kind prior to today; is
3 that correct?
4 A. That is correct.
5 Q. Okay. In your answers to Mr. Chabot's
6 questions in regard to the trading strategies,
7 you used a term that the strategies were
8 recurring.
9 Do you recall using that term?
10 A. No. That was --
11 Q. He took you down kind of a list.
12 A. Right.
13 Q. One by one, the inc-ing, the non-firm
14 imports, exports, the Death Star Load ship, et
15 cetera, and asked you whether --
16 A. Whether they occurred one time only or
17 whether they happened on more than one occasion.
18 Q. Right. That's the line of questions
19 that I want you to focus on now.
20 Are you familiar with what I'm
21 asking you about now?
22 A. Yes.
23 Q. My questions now, I'd like to try to
24 get some understanding of when they started to
25 recur and when they stopped recurring.

1 I believe that with respect to
2 one of the strategies, your testimony is that
3 they stopped in August of 2000; is that correct?
4 A. My testimony is that that was my
5 understanding, was that is when it stopped.
6 Q. That would have been the non-firm export
7 that you referred to in your December 6th memo
8 on pages 3 and 4?
9 A. Yes.
10 Q. From the work that you were doing at
11 that time in preparing what ultimately became
12 your December 6th memo, did you come to any
13 understanding as to when the strategies first
14 began to commence?
15 A. Which strategy are you talking about in
16 particular?
17 Q. Well, as I appreciate it, you have
18 broken these down into two big picture
19 strategies. On the one hand, there would be
20 some inc-ing load-type strategies, and on the
21 other would be the relieving congestion, or
22 congestion strategies, correct?
23 A. Yes.
24 Q. Let's take those one at a time.
25 Did you reach any understanding

1 as to when the inc-ing load strategies began?
2 A. No.
3 Q. How about the congestion strategies, did
4 you reach any understanding as to when the
5 congestion strategies began?
6 A. No.
7 Q. Are you familiar at all with an expert
8 witness who has filed testimony in this case
9 named Robert McCullough?
10 A. I'm aware of him.
11 Q. Have you seen any of the testimony that
12 he has filed in this case?
13 A. No. Just what is reported in the
14 media.
15 Q. I'm sorry, what is reported where?
16 A. In the media, in the newspapers.
17 Q. Okay. I'll paraphrase some of what Mr.
18 McCullough says; and I'm not trying to quote
19 him. But I reach the understanding from reading
20 his testimony filed in his case that he
21 testified to certain facts he perceived which
22 indicated to him, anyway, that these strategies
23 more than likely commenced in May of 2000.
24 Are you familiar with that
25 testimony at all?

1 A. No.
2 Q. In your work in preparing this memo,
3 December 6th, 2000, did you have anything that
4 indicated to you that these strategies may have
5 began in May of 2000?
6 A. No.
7 Q. Did you obtain any information which
8 indicated to you that these strategies, either
9 the inc-ing strategies or the congestion
10 strategies, may have been occurring prior to May
11 of 2000?
12 A. Other than flipping through your exhibits
13 today and seeing some e-mails dated 1999, no.
14 Q. In particular, 1999 would have been
15 referring to the Silver Peak event?
16 A. I think there were -- really I would be
17 loathed to go back through both of these
18 binders. But it seems to me that I saw a page
19 or two referencing different strategies, maybe
20 even some that I wasn't even aware of. But that
21 the dates preceded May of 2000. That's in your
22 documents.
23 Q. Right. I'm trying to get you to focus
24 on the work that you were doing at the time and
25 the discussions you were having with traders and

1 discussions you were having with Mr. Yoder,
2 whatever you were doing at the time that led up
3 to the preparation of the December 6th, 2000,
4 memo is what I'm asking you to focus on.
5 A. If I understand your question, then to
6 be -- did I, in the course of preparing this
7 memorandum, learn whether the trade trading
8 strategies had all begun after May 2000 or
9 before May 2000, the answer would be no, I don't
10 recall hearing either of those two facts.
11 Q. If I understand you correctly, you
12 wouldn't have seen anything that indicated that
13 they occurred before May of 2000?
14 A. I don't remember hearing anything or
15 seeing anything.
16 Q. Now, setting aside for a moment the
17 non-firm export strategy, which appears from your
18 testimony to have stopped in or around August of
19 2000, and referring to the other strategies, from
20 what you said today, did you come to reach an
21 understanding as to when those strategies stopped
22 recurring, or ceased recurring?
23 A. Well, as I said earlier, my memory is
24 that at the November meeting of the litigation
25 team, that Richard Sanders inquired as to whether

1 certain of these strategies were ongoing, and I
2 recall the traders at that time saying that they
3 weren't.
4 Q. That they were not?
5 A. That they were not.
6 Q. So as of November 2000, you had
7 information which led you to believe that the
8 strategies included in your December 6th, 2000,
9 memorandum, had stopped?
10 A. Well, the danger of generalizing here is
11 that each one of these strategies is different.
12 The ones that involved deceptive practices, it
13 was my understanding that those had stopped.
14 Q. And you reached that understanding based
15 on what again, please?
16 A. Based upon my memory of Richard Sanders
17 asking the traders whether these strategies were
18 continuing.
19 Q. Did I understand from your testimony
20 earlier in response to Mr. Chabot's questions
21 that after your December 6th, 2000, memorandum
22 was delivered to senior management, or whoever it
23 was delivered to, that you obtained additional
24 information as to the termination of the
25 strategies, or did I misunderstand that?

1 A. I think we were talking about whether a
2 directive had gone out from Enron management to
3 the traders. And we talked about Mr. Sanders.
4 Q. Would you explain that for me. I'm not
5 sure I understand that yet.
6 A. I don't have a firsthand recollection of
7 whether I remember Mr. Sanders doing this or
8 not, but Mr. Sanders has testified under oath
9 that following receipt of my memorandum, he
10 advised the traders to cease any of the
11 practices that were still continuing.
12 Q. Other than what you heard him testify to
13 at the senate, did you see or hear or observe
14 anything after the delivery of your December 6th
15 memo that led you to believe that such
16 directives had been given out?
17 A. Not that I remember.
18 Q. You are not saying that it didn't
19 happen, but you are just saying that you don't
20 remember?
21 A. Exactly.
22 Q. But your testimony is that prior to any
23 such directives, you believe that the strategies
24 had stopped by the end of November 2000, insofar
25 as the deceptive strategies included deceptive

1 acts or practices?
2 A. Yes.
3 Q. That is your testimony; is that correct?
4 A. Yes. That was my understanding.
5 Q. Now, you may also remember Mr. Chabot
6 asked you some questions -- or you gave some
7 answers, anyway, about the strategies and whether
8 they occurred on the real time desk or the
9 day-ahead desk.
10 Do you recall those answers?
11 A. Yes.
12 Q. Yes?
13 A. Yes.
14 Q. When you refer to the real time desk
15 and the day-ahead desk, are you talking about
16 the California spot market, or are you talking
17 about something else?
18 A. I'm talking about the California spot
19 market with respect to the day-ahead desk. With
20 the real time desk, that desk sold into the
21 California spot market, but it also sold and
22 bought into and from the WSCC spot market. So
23 California plus the rest of the west.
24 Q. Was it your understanding that these
25 strategies, either on the real time desk or the

1 day-ahead desk, were strategies that were
2 employed only in the spot market, or were they
3 employed in forward markets as well?
4 A. By their nature, these strategies could
5 only be involved in the California ISO markets
6 and the CAL PX markets.
7 Q. Why is that?
8 A. Well, if you look through each one of
9 these strategies in the memorandum, they only
10 involve bidding into those markets or scheduling
11 energy through the California ISO.
12 Q. So by definition and operation, they
13 were limited to spot market transactions; is that
14 a fair statement?
15 A. By definition and by their nature, they
16 were limited only to the CAL PX and the CAL ISO
17 market. And my understanding is the current
18 definition of spot market by FERC is deliveries
19 within 24 hours entered into day of or day prior
20 to. And so under that definition, yes, they
21 would be spot market.
22 Q. In your memo of December 6th, I believe
23 it's on page 2, in the third full paragraph
24 there, you have a reference to causing the
25 favorable movement in real time expose prices.

1 Do you see that reference?
2 A. I do. Let me just read that for a
3 moment.
4 Yes.
5 Q. When you used the term "favorable
6 movement," what did you mean?
7 A. I meant that the expose price would be
8 higher than the PX price.
9 Q. In any of your work, or any of the work
10 that anybody else was doing of which you were
11 aware, did you do any work to come to or arrive
12 at any conclusions as to the size of any
13 economic impact in a, quote, "favorable," close
14 quote, way as a consequence of any of these
15 strategies?
16 A. Let's just be clear here. The context
17 of this paragraph talks about the ISOs'
18 forecasting and how the actions of the ISO would
19 cause a favorable movement. I wasn't referring
20 to anything that was done by Enron traders in
21 that paragraph.
22 Q. Let me ask the question another way,
23 then.
24 In any of your work, or any of
25 the other work of which you are aware that was

1 done prior to the preparation and delivery of
2 the December 6th memo, was there any study done
3 by anybody that you know about that was directed
4 at or intended to arrive at a conclusion as to
5 whether any strategies employed by Enron had any
6 economic impact on the spot market that would
7 have increased prices?
8 A. I'm not aware of any such study.
9 Q. You didn't attempt to do that yourself?
10 A. No.
11 Q. Do you know of anybody else who did?
12 A. No.
13 Q. Did you reach any opinion on your own?
14 A. Any opinions that I had I put into my
15 memorandum.
16 Q. I want to ask you about that, too.
17 From your testimony, I gathered
18 that this memorandum took a while to come to its
19 final draft; is that a fair statement?
20 A. Yes.
21 Q. From your testimony, I conclude that the
22 time that it took to arrive at a final draft
23 included several rewrites; it involved discussions
24 with a number of different traders and a number
25 of different people; is that true?

1 A. That is true.
2 Q. And that effort also included discussions
3 between you and your superiors at Stoel Rives;
4 is that correct?
5 A. Yes.
6 Q. You mentioned a gentleman -- Marcus
7 Wood, is that his name?
8 A. Yes. You said superiors, plural. But
9 essentially I just discussed the substance of the
10 memorandum with Marcus Wood only.
11 Q. Okay. In its final version that it was
12 finally delivered by you and signed off on by
13 Mr. Wood, did it include everything in it that
14 you believed as a lawyer you should advise your
15 client or warn him about in so far as any of
16 these conducts or any of these strategies, or
17 did it leave anything out?
18 A. No. The purpose of the memorandum was
19 to describe the trading strategy. The purpose
20 was not to do an analysis under, for example,
21 state criminal law statutes or to analyze under
22 FERC's precedence whether these things were
23 improper or anything like that. It was more
24 just to understand and describe.
25 Q. Okay. That's good to know.

1 But another way to ask the
2 question: Did you sugar coat in any way the
3 information that you provided to make it look
4 better than it actually was, or did you tell it
5 like it was as you understood it?
6 A. I didn't sugar coat anything, to use
7 your term. I tried to, in fact, as I described
8 things -- tried to take the most conservative
9 view or interpretation of how the -- how a
10 certain act would be perceived. There are two
11 sides to the story, and I wasn't actually very
12 focused on telling the side of the story that --
13 of positive benefits of these strategies or
14 anything like that.
15 Q. But if there was anything that you were
16 aware of that was a quote, "bad fact," close
17 quote, did you include it in the memo, or did
18 you --
19 A. Yes.
20 Q. Is the answer yes?
21 A. The answer is yes.
22 Q. So you didn't leave out any bad facts?
23 A. None that I was aware of.
24 Q. Okay. I gathered from your earlier
25 testimony as well when you mentioned several

1 conversations with Mr. Yoder about the
2 preparation of the memo -- do you recall those
3 where you said that you got together and
4 discussed it on the white board, drew maps of
5 California and arrows and what have you to try
6 to understand?
7 Do you recall that testimony?
8 A. Yes.
9 Q. I gathered from what you said that these
10 were somewhat difficult to understand. Is that
11 true or not true?
12 A. It's both true and an understatement.
13 Q. Did you find it more difficult to
14 understand because there was some sort of
15 obfuscation going on? Why did you find them
16 difficult to understand?
17 A. There was no obfuscation, at least that
18 I was aware of. The traders were very candid
19 about what they were doing, and in fact, didn't
20 see that anything they were doing was wrong.
21 But they were complicated because they involved a
22 lot of different factors. They involved
23 understanding the California PX tariffs and the
24 California ISO tariffs collectively, about a
25 thousand pages of rules. They required some

1 understanding of how energy was scheduled and an
2 understanding of how the different auctions
3 worked. There were four different auctions to
4 understand. You also had to understand how
5 energy was scheduled onto the ISO grid and the
6 interaction with the rules there.
7 And this was all very new to
8 me. I had only been -- I only started looking
9 at the tariffs two weeks prior to this. And so
10 at least to me it was very complicated.
11 Q. You just made a statement to the effect
12 that these traders -- I might be paraphrasing --
13 didn't think that they were doing anything wrong.
14 Do you recall that?
15 A. Yes.
16 Q. What led you to reach the understanding
17 that these traders didn't think they were doing
18 anything wrong?
19 A. Just my general sense from statements
20 made at the October 3rd meeting and subsequent
21 discussions. For example, the traders would say:
22 Well, you know, there is nothing in the tariff
23 that says we can't do this.
24 Q. In your memo of December 6th, you have
25 a section on the ISO tariff outlined at letter

1 C. And any discussion after that --
2 Do you see that?
3 A. Are you talking about the gaming
4 provisions from the ISO tariff?
5 Q. I'm talking about the material that
6 appears on pages 7 and 8 of the December 6th
7 memo, the bottom of page 7, top of page 8.
8 A. Yes.
9 Q. What was that section of your memo
10 intended to convey?
11 A. That was to provide background to the
12 litigation team so that they would understand
13 what the pertinent ISO rules were that applied
14 to this behavior. It was also to alert in-house
15 counsel that some of these practices might run
16 afoul of the gaming provisions of the ISO
17 tariff.
18 Q. Once again, my question particularly with
19 respect to this section of your memo, was it in
20 any way sugar coated from what you learned and
21 observed, or did it include everything that you
22 became aware of?
23 A. I included everything that I became
24 aware of that was relevant to the purpose of the
25 memorandum.

1 MR. HULKOWER: Hang on one
2 second, please.
3 (Discussion off the record.)
4 MR. HULKOWER: Okay. We're
5 back.
6 MR. MOORE: Mr. Hall, I think
7 those are all the question I have at this time.
8 Thank you very much.
9 THE WITNESS: Thank you.
10 MR. HULKOWER: We're finished.
11 MR. CHABOT: Actually, do you
12 have anything?
13 MR. HULKOWER: No.
14 MR. CHABOT: I have one
15 follow-up question based on Mr. Moore's
16 questions.
17 EXAMINATION
18 BY MR. CHABOT:
19 Q. Were you aware that the Brobeck law firm
20 was, in fact, doing an analysis of the legal
21 implications of the conduct of Enron and others?
22 A. If you are talking about the memorandum
23 that has recently come to light --
24 Q. In Volume 2, which is Exhibit 3, at
25 page AD 223, it begins there, the corresponding

1 EC numbers 901, the last three digits.
2 A. Okay.
3 Q. Is that the memorandum, the document
4 that you just referred to as recently having
5 come to light?
6 A. Yes.
7 Q. And were you at the time, concurrently
8 in the October, November, December time period of
9 2000, aware that Brobeck was preparing such a
10 memorandum?
11 A. No.
12 Q. Or had prepared such a memorandum?
13 A. No.
14 Q. When was the first time that you became
15 aware of that?
16 A. Within the past few weeks.
17 Q. Had anyone told you not to look at the
18 legal implications of the conduct that you were
19 describing in the December 6th memo?
20 A. No.
21 Q. So it's fair to say that you just
22 regard it as outside the scope of what you had
23 been asked to do by Mr. Yoder?
24 A. Yes. It would have been outside the
25 scope of what I had been asked to do, but

1 outside the scope of my expertise.
2 Q. With respect to your professional
3 expertise, when you were describing in response
4 to Mr. Moore's questions the fact that these
5 practices could only take place within the ISO
6 or PX markets in California, you did not mean to
7 contest the fact, did you, that energy with
8 respect to those transactions was in some
9 instances coming from outside of the state of
10 California?
11 A. No.
12 Q. Or that it was being transmitted in
13 interstate commerce outside of California, between
14 areas outside of California and in California?
15 A. No.
16 Q. Do you have any opinion whatsoever as to
17 whether or not these transactions had an impact
18 on the markets outside of California?
19 A. I don't feel qualified to say one way
20 or the other.
21 Q. Would that be true with respect to both
22 short-term and long-term markets?
23 A. Yes.
24 MR. CHABOT: That's all I have,
25 unless you have anything.

1 MR. MOORE: I have nothing
2 further at this time.
3 MR. CHABOT: With that we will
4 close the record. But I believe the court
5 reporter has some questions.
6 MR. HULKOWER: We would like to
7 read and sign this.
8 (The deposition concluded at
9 12:00 p.m.)
10 (By agreement between counsel
11 and the witness, signature was reserved.)
12
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CERTIFICATE

I, Phillip A. Rader, do hereby certify that pursuant to the Rules of Civil Procedure, the witness named herein appeared before me at the time and place set forth in the caption herein; that at the said time and place, I reported in stenotype all testimony adduced and other oral proceedings had in the foregoing matter; and that the foregoing transcript pages constitute a full, true and correct record of such testimony adduced and oral proceeding had and of the whole thereof.

IN WITNESS HEREOF, I have hereunto set my hand this _____ day of _____, 2002.

_____ _____

Signature Expiration Date

STOEL RIVES LLP
ATTORNEYS
900 SW FIFTH AVENUE, SUITE 2600
PORTLAND, OR 97204-1268
Telephone (503) 224-3380
Fax (503) 220-2480
Billing Inquiries 1-800-305-8453

Committee on Governmental Affairs
EXHIBIT #A-67

0045413 ENRON NORTH AMERICA
00002 CALIFORNIA POWER MATTERS

INVOICE DATE 11/27/00
INVOICE NUMBER 2829426
M-W

Employer's Identification No. 93-0408771

DATE	CURRENT SERVICES THROUGH 10/31/00	ATTY	HOURS
	strategies to determine if consistent with ISO tariff		
	TOTAL CURRENT SERVICES		**$27,174.00**

TIME RECAP	HOURS
STEPHEN C. HALL	147.8
* PROJ ASST 5	9.5
TIMEKEEPER TOTALS	157.3

* NON-ATTORNEY TIME

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ATTORNEYS
900 SW FIFTH AVENUE, SUITE 2600
PORTLAND, OR 97204-1268
Telephone (503) 224-3380
Fax (503) 220-2480
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Employer's Identification No. 93-0408771

CURRENT DISBURSEMENTS AND OTHER CHARGES THROUGH 10/31/00

DATE	ITEM	AMOUNT
10/17/00	Photocopies	233.52
	TOTAL CURRENT CHARGES	**$233.52**

TOTAL FEE BILLINGS FOR THIS MATTER DURING CLIENTS FISCAL YEAR 41,142.00

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ATTORNEYS
900 SW FIFTH AVENUE, SUITE 2600
PORTLAND, OR 97204-1268
Telephone (503) 224-3380
Fax (503) 220-2480
Billing Inquiries 1-800-305-8453

TO: ENRON CAPITAL & TRADE RESOURCES CORP
MR CHRISTIAN YODER
121 SW SALMON ST,. 3WTC0306
PORTLAND, OR 97204

INVOICE DATE 11/27/00
INVOICE NUMBER 2829426
M-W

Employer's Identification No. 93-0408771

0045413 ENRON NORTH AMERICA
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STATEMENT OF SERVICES, DISBURSEMENTS, AND OTHER CHARGES THROUGH 10/31/00

Balance From Previous Statement		$13,968.00
Payment(s) Received		.00
Current Activity:		
Fees for Professional Services (see attached for detail)	$27,174.00	
Disbursements and Other Charges	233.52	
Current Amount		27,407.52
TOTAL BALANCE DUE		$41,375.52

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Statements are due within 30 days after the invoice date printed on the statement. A monthly late fee equal to 9 percent per annum, commencing on the due date, will be charged on all amounts not paid within 60 days after the invoice date.

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PORTLAND, OR 97204-1268
Telephone (503) 224-3380
Fax (503) 220-2480
Billing Inquiries 1-800-305-8453

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Fax (503) 220-2480
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00002	CALIFORNIA POWER MATTERS	INVOICE NUMBER	2829426
			M-W

Employer's Identification No. 93-0468771

DATE	CURRENT SERVICES THROUGH 10/31/00	ATTY	HOURS
10/01/00	Read background materials on CalPX and Cal ISO	SCH	1.5
10/02/00	Read e-mails relating to CPUC subpoena; office conference with Shari Stack and Christian Yoder re CAISO definition of firm energy and inc/dec; update CAISO tariff; legal research re CAISO definition of firm energy and inc/dec pricing	SCH	9.7
10/03/00	All day meeting and strategy session with Christian Yoder, Mary Hain, Jim Steffes, Richard Sanders, Tim Belden, and others, to (1) comply with CPUC subpoena and (2) learn about trading strategies used by traders; study inc/dec pricing and ten-minute interval issues	SCH	9.3
10/04/00	Update CAISO tariff; conference with Christian Yoder re documentation of trading strategies; teleconference with Mark Haedicke, Richard Sanders, Christian Yoder, Gary Fergus; organize customer list for letter notifying customers of subpoena; review Enron's pleadings in ER00-2383; draft memorandum documenting trading strategies; conference with Mary Hain	SCH	8.4
10/05/00	Review Enron's draft petition and protest in ISO's filing with FERC to extend price caps under Tariff Amendment 31; review Enron's pleadings in FERC proceeding to implement ten-minute intervals; review Market Surveillance Committee's Sept 21report re long-term price-cap policy; update ISO tariff; legal research re date of Fed Reg notice of investigation into Cal Mkt; study settlement procedures for inc/dec instructed energy deviations	SCH	9.5
10/06/00	Review draft letter to CPUC; office conference with Edward Einowski re authority of SMUD to enter into a long-term contract; work on definition of CAISO energy; work with Diane Raptor to update CAISO tariff; study tariff settlement procedures in order to define CAISO price for Master Agreement; e-mail to Christian Yoder re SMUD's authority	SCH	4.7
10/09/00	Office conference with Christian Yoder re status of subpoena, confidentiality letter, CAISO energy definition, CAISO tariff update; review Amendment 26 to CAISO tariff; conference with Diane Raptor to review progress of tariff updating and resolve issues relating to same; study CAISO tariff to develop definition of CAISO energy; review SLICE contract principles in preparation for meeting with Greg Wolfe and Christian Yoder; draft memorandum summarizing trading strategies used by traders	SCH	9.6
*10/10/00	Create a FERC Electric Tariff index	PA5	6.0
10/10/00	Study FERC Order re conversion to ten-minute markets to determine effect on Enron's definition of CAISO energy; review CMUA complaint; edit draft summary of "Fixing What is Broken: What Steps Should FERC Take to	SCH	9.5

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ATTORNEYS
900 SW FIFTH AVENUE, SUITE 2600
PORTLAND, OR 97204-1268
Telephone (503) 224-3380
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DATE	CURRENT SERVICES THROUGH 10/31/00	ATTY	HOURS
	Complete California's Power Markets?"; conference with Greg Wolfe re Slice contract issues; conference with Tim Belden re CAISO price and schedule adjustment; conference with Christian Yoder re assumption of responsibilities in his absence; study report "Fixing What is Broken: What Steps Should FERC Take to Complete California's Power Markets?"		
*10/11/00	Create a FERC Electric Tariff index	PA5	3.5
10/11/00	Draft and edit summary of white paper on fixing California's market; work on definition of "CAISO Energy," office conference with Tracy Ngo re negotiations with PG&E over events of default provision in RFP; telephone conference with Tracy Ngo, Christian Yoder, and PG&E counsel re same	SCH	5.0
10/12/00	Review terms of BPA's slice contract; work on definition of "CAISO energy," office conference with Christian Yoder re definition of "CAISO energy," telephone conference with Shari Stack, Christian Yoder, Heather Dunston, and counsel for Dynegy re definition of "CAISO energy," telephone conference with counsel for PG&E, Christian Yoder, Chris Foster, Tracy Ngo re terms of Enron/PG&E transaction; review ISO settlement procedures; telephone conference with Shari Stack and Christian Yoder to discuss PG&E's proposed revisions to agreement	SCH	8.8
10/13/00	Work with Chris Foster, Tracy Ngo to draft terms of Enron/PG&E transaction; telephone conference with counsel for PG&E, Chris Foster, Tracy Ngo re terms of Enron/PG&E transaction; review terms of BPA's slice contract; analyze PG&E's proposed changes; work on definition of CAISO Energy	SCH	7.0
10/16/00	Work on draft definition of "CAISO Energy," "Adjustment Payments," and conversion of hourly ex post pricing to inc/dec pricing; work session with Shari Stack and Bob Badeer to draft definition of "CAISO Energy," "Adjustment Payments," and conversion of hourly ex post pricing to inc/dec pricing; review draft of EPMI's motion to submit White Paper to FERC and accompanying brief; conference with Mary Hain to discuss strategy for brief and recommended edits	SCH	8.0
10/17/00	Draft letter to counterparties notifying them of CPUC subpoena; review EPMI Motion to Lodge White Paper with FERC; work on definition of Adjustment Payment; prepare sheet of results of Adjustment Payment under various inc/dec scenarios; revise definition of "CAISO Energy"; prepare for meeting with Tim Belden re CAISO Energy	SCH	8.0
10/18/00	Analyze proposed answer to CMUA complaint; work session with Tim Belden, Bob Badeer, Shari Stack to work through my definition of CAISO	SCH	3.0

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ATTORNEYS
900 SW FIFTH AVENUE, SUITE 2600
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			M-W

Employer's Identification No. 93-0408771

DATE	CURRENT SERVICES THROUGH 10/31/00	ATTY	HOURS
	Energy and Adjustment Payment; draft memorandum to Christian Yoder summarizing status of ongoing projects		
10/23/00	Review CAISO Energy definition and inc/dec pricing issue with Christian Yoder; review status of indemnity agreement with Cal PX; review status of customer letter re confidentiality; analyze recent amendments to ISO tariff to confirm accuracy of ISO's published tariff	SCH	5.0
10/24/00	Analyze FERC order relating to ISO tariff Amendment 29; draft memorandum summarizing trading strategies; check the CAISO and Cal PX websites for new filings; conference calls (2) with Tim Belden, Mary Hain Jeff Richter, Christian Yoder and others re CPUC subpoena	SCH	7.5
10/25/00	Review Elizabeth Sager's proposed examples to demonstrate application of inc/dec ex post pricing to Adjustment Payment; make redline changes to proposed examples; review Amendments No. 25 and 26 to CAISO tariff	SCH	4.4
10/26/00	Review next draft of proposed examples to demonstrate application of Adjustment Payment under inc/dec ex post pricing; analyze Amendment No. 30 to CAISO for Sheila Tweed; meeting with Christian Yoder to analyze effect of the ISO's proposed pro-rata allocation of forward contract costs to scheduling coordinators	SCH	3.0
10/27/00	Review ISO Board's resolution to implement load differentiated price caps; telephone call to Per Ramfjord to discuss Enron's contract rights following ISO's new price cap and PSE's FERC filing; review ISO's Market Surveillance Report; conference with Christian Yoder to analyze PSE's put option agreements following PSE's FERC filing and to develop a strategy for responding to this development; update ISO tariff	SCH	6.2
10/28/00	Bring Enron's copy of the ISO tariff up-to-date by reviewing the ISO's most recent FERC filings, comparing to existing tariff, printing out new filings from website, inserting new tariff pages into binders, and marking out superceded sections	SCH	7.4
10/30/00	Work session with Christian Yoder to develop and understand trading strategies; review CAISO energy definition proposed by Southern Energy; respond to Shari Stack by e-mail, explaining differences between Enron's definition and Southern's definition; locate BPA statute for Mary Hain ; analyze ISO tariff to determine if certain trading strategies violate tariff	SCH	5.7
10/31/00	Review ISO tariff provisions relating to schedule adjustments in preparation for conference call with Southern Energy re definition of CAISO Energy; telephone call to Shari Stack re Southern's CAISO definition; conference with Christian Yoder to discuss Schedule Adjustments; analyze certain trading	SCH	6.6

Committee on Governmental Affairs
EXHIBIT #A-68

From: Sarah Novosel
Sent: Tuesday, August 14, 2001 7:05 PM
Subject: FERC Presentation on California/West Wholesale Market

---------- Forwarded by Sarah Novosel/Corp/Enron on 09/15/2000 05:16 PM ----------

Mary Hain@ECT
08/29/2000 08:11 PM

To: James D Steffes/HOU/EES@EES, David W Delainey/HOU/ECT@ECT, John J Lavorato/Corp/Enron@Enron, Christopher F Calger/PDX/ECT@ECT, Tim Belden/HOU/ECT@ECT, Joe Hartsoe@Enron, Paul Kaufman/PDX/ECT@ECT, Sarah Novosel/Corp/Enron@ENRON, David Parquet/SF/ECT@ECT, jdasovic@ees , Mona Petrochko, Kevin M Presto/HOU/ECT@ECT, Richard Shapiro, Steve Kean, Chris H Foster/HOU/ECT@ECT, Robert Badeer/HOU/ECT@ECT, Jeff Richter/HOU/ECT@ECT, Susan J Mara/SFO/EES@EES
cc: Christi Nicolay

Subject: FERC Presentation on California/West Wholesale Market

Last Thursday, I made the first attached presentation to the FERC Staff at the power marketer's meeting on the FERC's investigation of the wholesale market in the West (and in particular California). Ellen Wolf (of Tabors Caramanis) and I created this presentation building on previous presentations by Tim Belden and Dave Parquet. In the presentation and the meeting we made the following points:

There isn't much FERC can do because the cause of the price spikes is not in the wholesale market. We discouraged FERC from taking any action that would hurt the vibrant wholesale market in the California and the rest of the West as well.

High prices logically resulted from scarcity and if the Commission does anything it should (1) investigate whether market power was being exercised by any party and, (2) if necessary to protect the market (while still incenting needed generation) establish a price cap at a scarcity rent level equal to the price at which loads were willing to interrupt.

The IOUs have not properly prepared for the risk of high prices caused by scarcity. They have failed to hedge and have underscheduled their load, therefore having to fill a large percentage of their load at ISO real time prices. My analogy was that this was like day trading your retirement fund as an asset allocation scheme.

The market would function better if more information was provided to the market.

The Commission should do whatever it can to incent participation by load.

To see the presentation, detach, save, and view in Powerpoint. When you do, you will find there are many "hidden" slides that were not part of the oral presentation but were provided to Staff in hard copy for additional information.

According to the head of the investigation (Scott Miller), the staff got alot more out of this meeting than Staff's previous meetings with the IOUs and the generators. Based on the numerous phone calls I've been getting, the Staff is looking into the data we provided.

I have also attached a revised version of the presentation that Tim sent to Scott Miller on Friday. Tim's version conveys the same message but takes a different approach to conveying the message. On Friday, Tim talked to Scott and answered some additional questions. Tim said that Enron is in favor of eliminating the mandatory PX buying requirement and would like the IOUs to be able to buy from Enron Online. He also explained more fully the existence of scarcity .

August 24 FERC
resentation to FERC.entation.ppt

What About the California Wholesale Market Really Needs Fixing?

August 24, 2000

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Summary

- High prices in peak periods are the result of scarcity and are necessary to incent needed generation investment
- California Retail/Wholesale Market Interaction
  - Retail customers are benefiting from the low prices during shoulder months caused by wholesale competition
  - The major problem is in the retail market where high peak period wholesale prices have not been mitigated by forward purchases
  - Underscheduling in forward market causes high demand and reliability problems during real time

Summary (Continued)

- Some wholesale market remedies are necessary now
  - The FERC should analyze whether there are Market Power Concerns Associated with Times of Scarcity and then determine appropriate level of Price Caps
  - Publicize Market Information
  - Encourage structure/ technological innovation to enhance demand side participation

Agenda

- Supply and demand data showing scarcity
- Current supply/demand economics
- Background - ISO and PX market structure
- Regulatory overlay
- Explanation of retail market problems
- Wholesale market issues requiring staff investigation
- Recommendations

Western Supply and Demand Fundamentals

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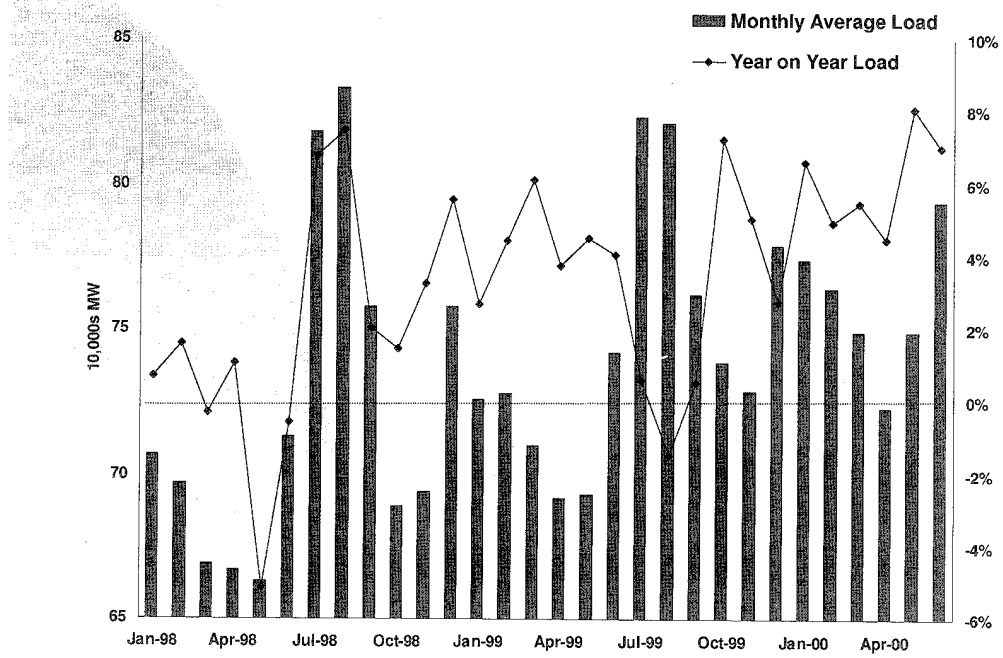
Western Supply and Demand Indicates Scarcity

- California competes vigorously with the rest of the growing west for increasingly scarce supplies
- Load growth fueled by strong economy
- No significant new generation in California since the 1980s
- Market was fooled by excellent hydro years
- The existing thermal generation fleet is aging: 61% > 30 years
- The complete lack of available NOx credits may have prevented generators from running

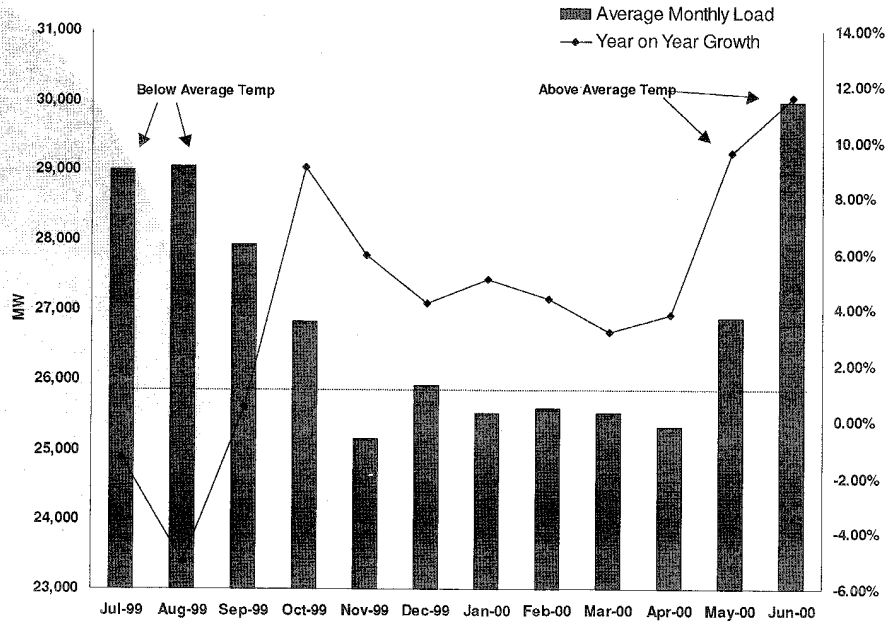
California Competes with the Rest of the West for Scarce Supplies

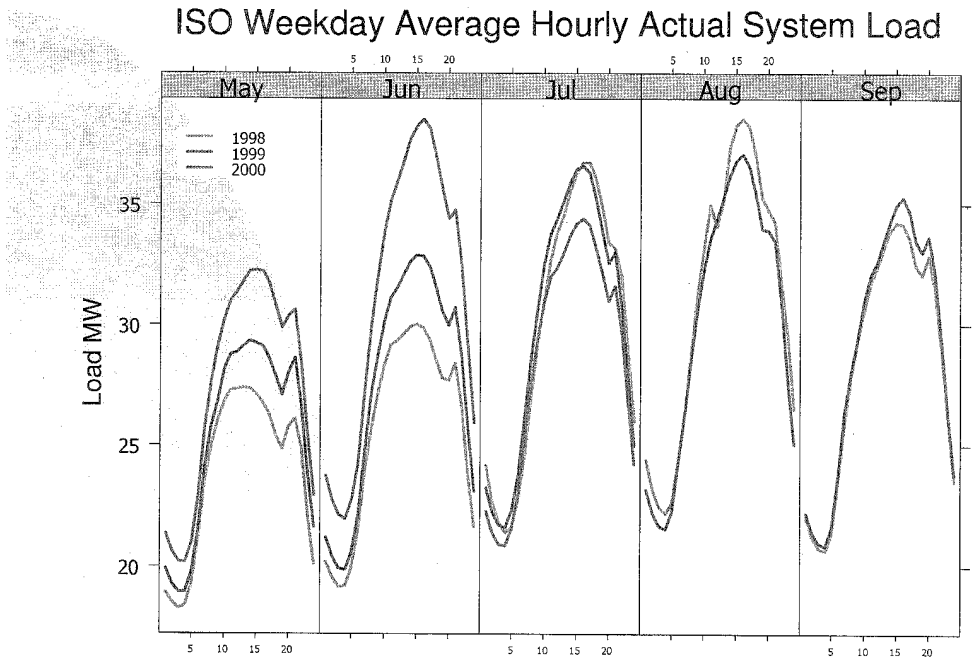
- Ample long distance transmission
- Traditional Northwest players' best opportunities often outside of the NW
  - Powerex Accesses Alberta Pool, Northwest, California
  - BPA often prices daily offer at PX Index price
  - Spread between COB and Northern California close to $0/MWh
- Turbine market is national --> Northwest and California must compete with all of North America for new resources

WSCC Load Growth



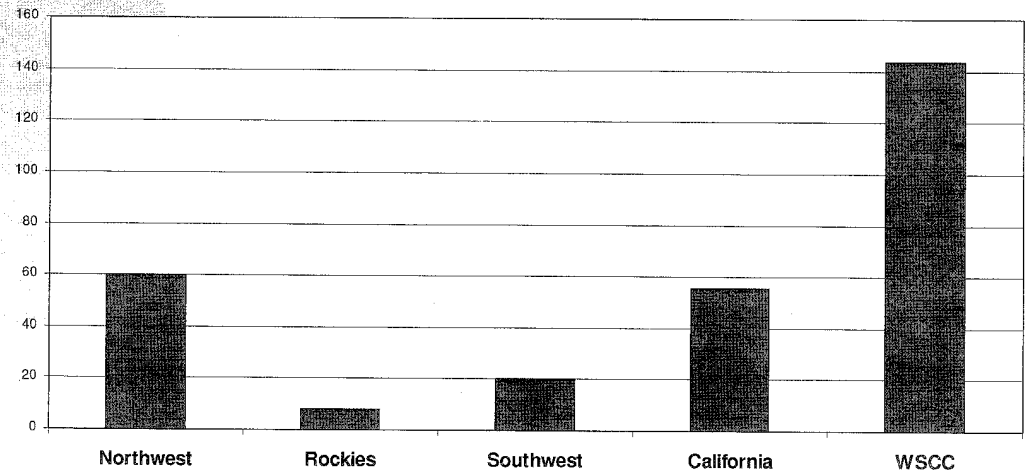
California ISO Load Growth




ISO Weekday Average Hourly Actual System Load
May
Jun
Jul
Aug
Sep
1998
1999
2000
Load MW
35
30
25
20
5
10
15
20

WSCC Loads (GW)

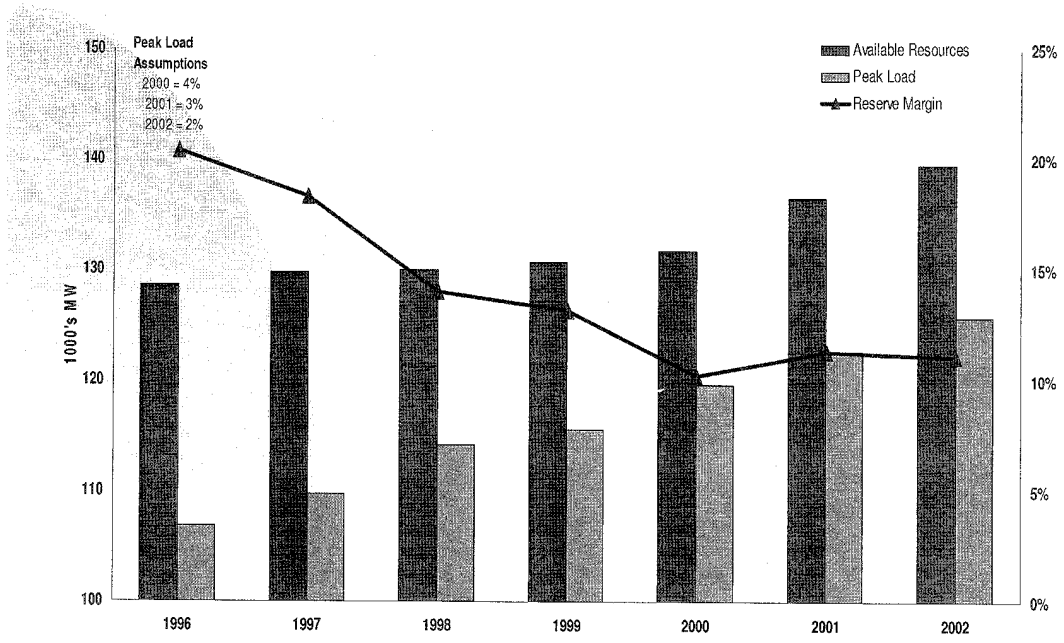
California is not an island and cannot develop a self-contained solution.



WSCC Capacity Additions

	Summer 2000	Summer 2001	Summer 2002
Northwest	7	760	851
California	-0-	1000	2648
Southwest / Rockies	908	2390	692
Total	915	4150	4191
Estimated Load Growth (Assumes 3% Escalation)	(3600)	(3708)	(3819)

WSCC Resources and Loads



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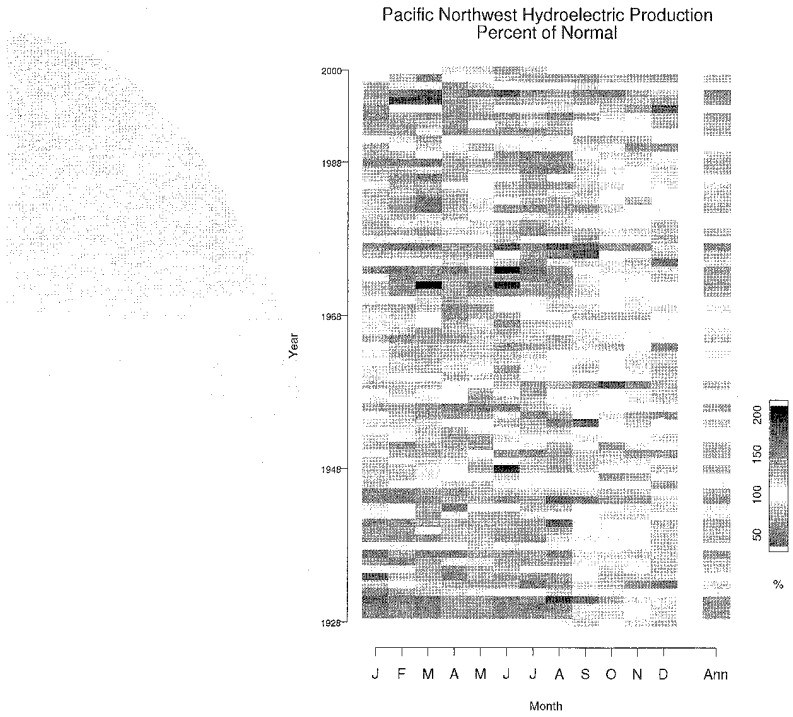
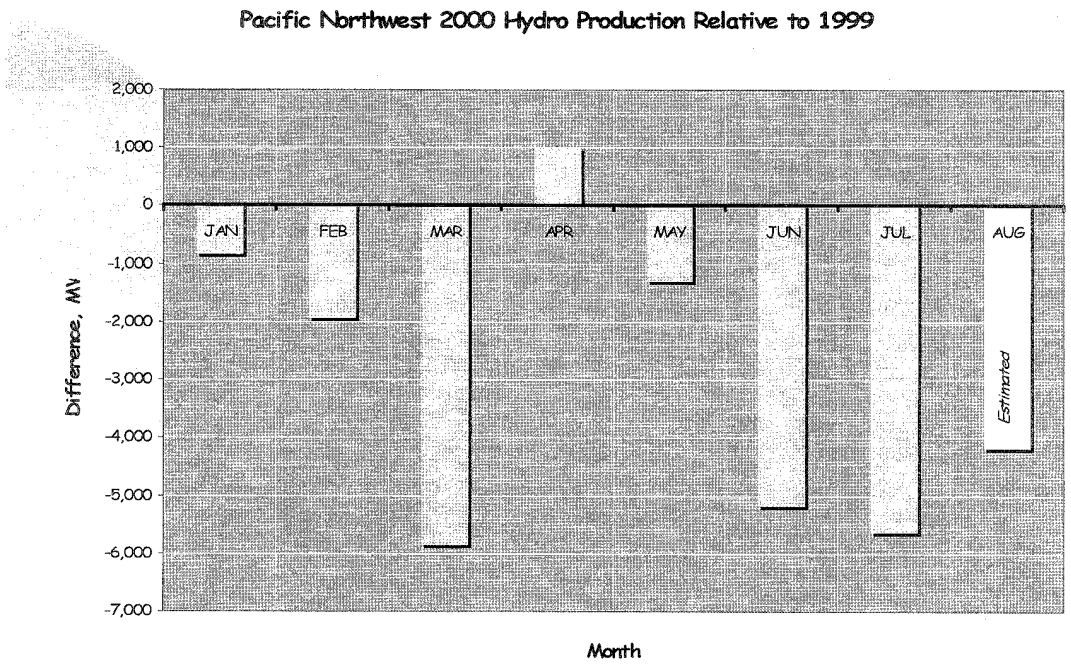
Has Recent Unusually Strong Hydro Fooled Us?

Volume Runoff Percent of Normal

	Columbia River	California
2000	93%	94%
1999	116%	108%
1998	98%	153%
1997	152%	84%
1996	138%	129%


Pacific Northwest Hydroelectric Production
Percent of Normal
Year
2000
1988
1968
1948
1928
J F M A M J J A S O N D Ann
Month
50 100 150 200
%



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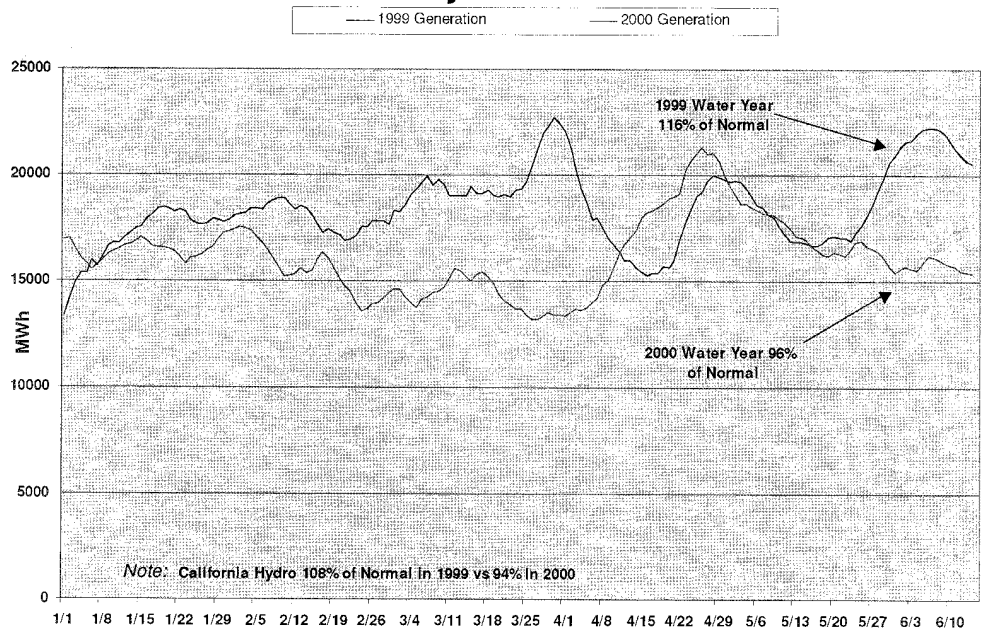
PNW Hydro Generation



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In Sum, Scarcity is Real - Generation is Needed

- Scarcity is real
- Energy prices driven by scarcity
- New generation required

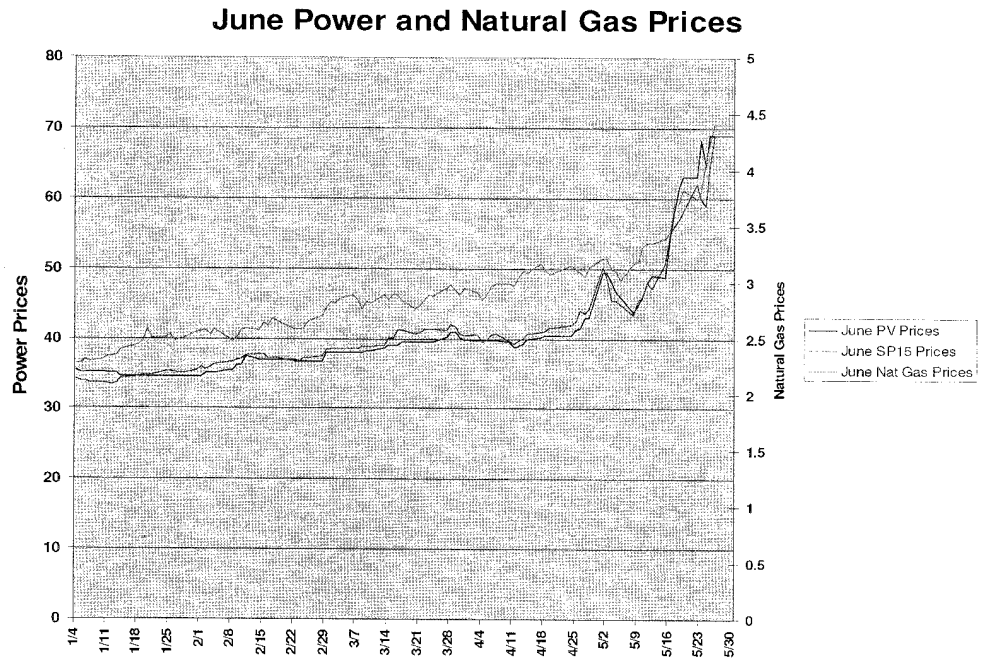
Current Supply/Demand Economics

FERC Regulatory Overlay

- Allowed Cal ISO to set "bid" caps
  - Price reduced from $250 to $750 on 10/1/99
  - Reduced from $750 to $500 on 6/29/00
  - Reduced from $500 to $250 on 8/7/00
- Cal PX - recently reduced from $2500 implicit cap to $350 explicit cap

Price Controls Will Perpetuate Scarcity

- Power plants are needed; Demand is still not very price responsive
- Operating costs of plants are increasing
  - Gas prices high
  - Gas generally is on the Margin in WSCC (I.e., Gas-fired generation sets the electricity generating market price)
- Power plant economics will keep generators from investing in generation if they anticipate price cap
- In state and out of state generation will be incented to sell out of state


June Power and Natural Gas Prices
Power Prices
Natural Gas Prices
80
70
60
50
40
30
20
10
0
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
1/4
1/11
1/18
1/25
2/1
2/8
2/15
2/22
2/29
3/7
3/14
3/21
3/28
4/4
4/11
4/18
4/25
5/2
5/9
5/16
5/23
5/30
June PV Prices
June SP15 Prices
June Nat Gas Prices

Power Plant Economics

- Investors will not invest in power plants if they can only earn short term marginal cost (I.e., the cost of fuel and operation and maintenance without earning a return on their investments)
- The $250 price cap may not provide a return on investment

Peaker Plant Economics

- Technology: GE LM 6000
- Fuel: Natural Gas
- Heat Rate: 10,000 Btu/Kwh
- Capacity: 48 MW
- Capital Structure:
  - 60% Debt @ 9%
  - 40% Equity @ 18%
  - 15 Year Amortization
- Total Cost to Build: $27 million
- Annual Capital Recovery: $3.7 million
- Annual Fixed O&M: $1.5 million
- Annual Total: $5.2 million

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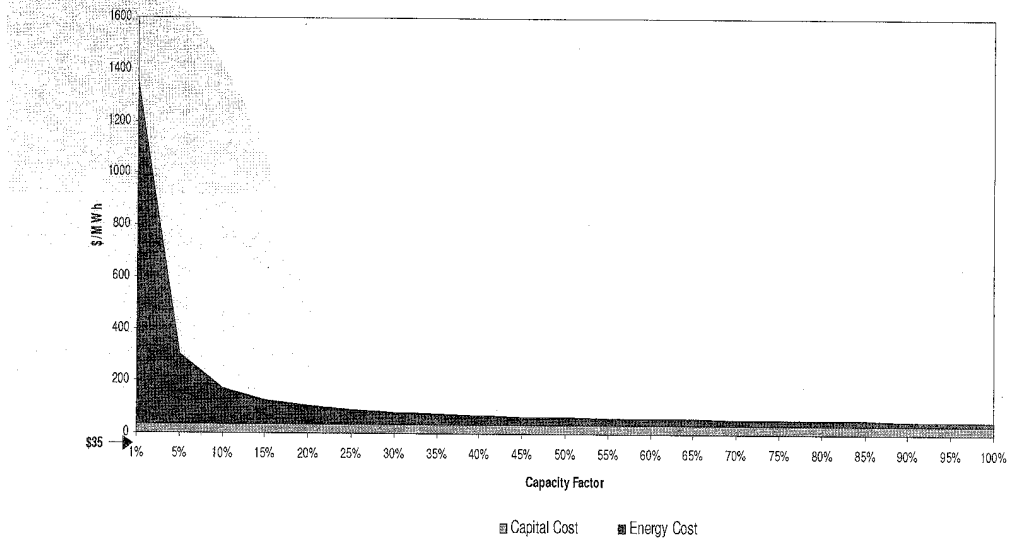
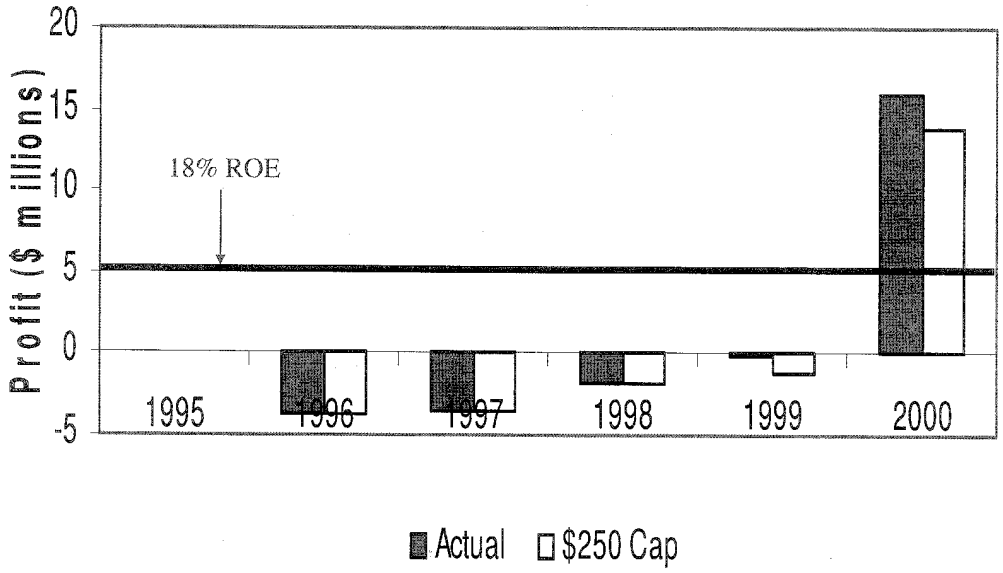
Baseload Plant Economics

Technology: Combined Cycle	GE Frame 7FA
Fuel:	Natural Gas
Heat Rate:	7,100 Btu/Kwh
Capacity:	280 MW
Capital Structure:	
◆ 50% Debt @ 9%	
◆ 50% Equity @ 15%	
◆ 15 Year Amortization	
Total Cost to Build:	$180 million
Annual Capital Recovery:	24 million
Annual Fixed O&M:	3 million
Annual Total:	$27 million

Peaker Plant Cost-to-Build



LM6000 Annual Profit



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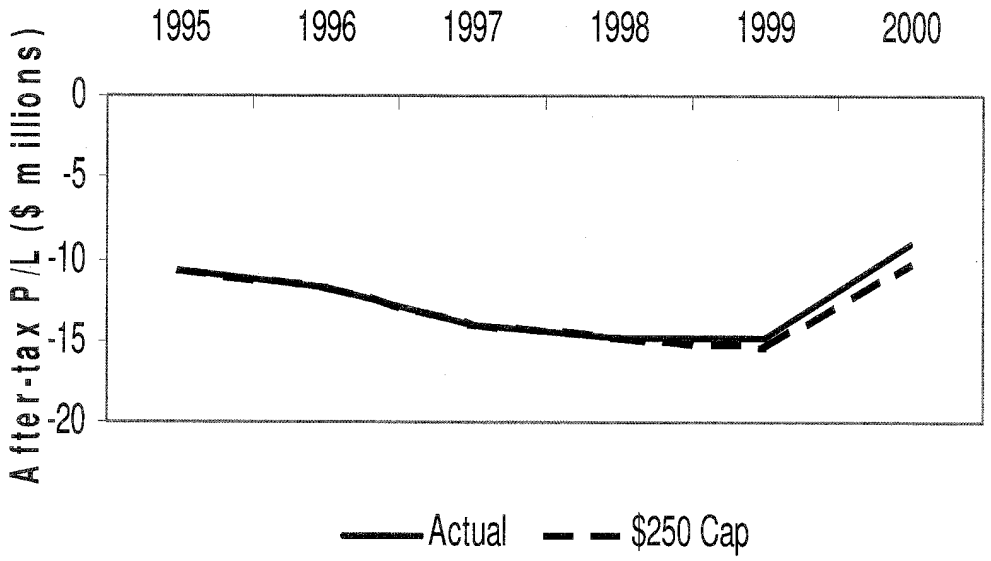
LM6000: Cumulative After-tax Profit/Loss



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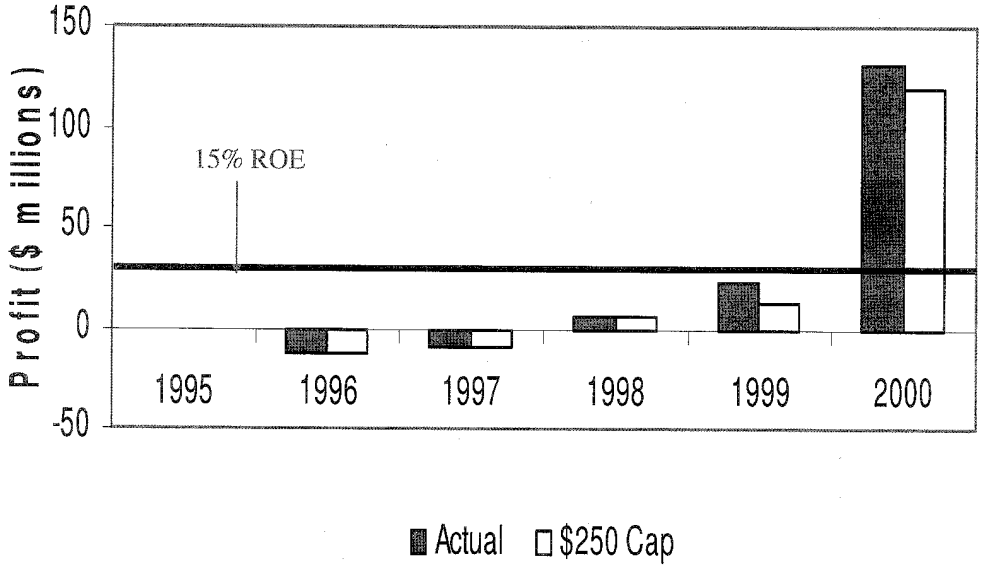
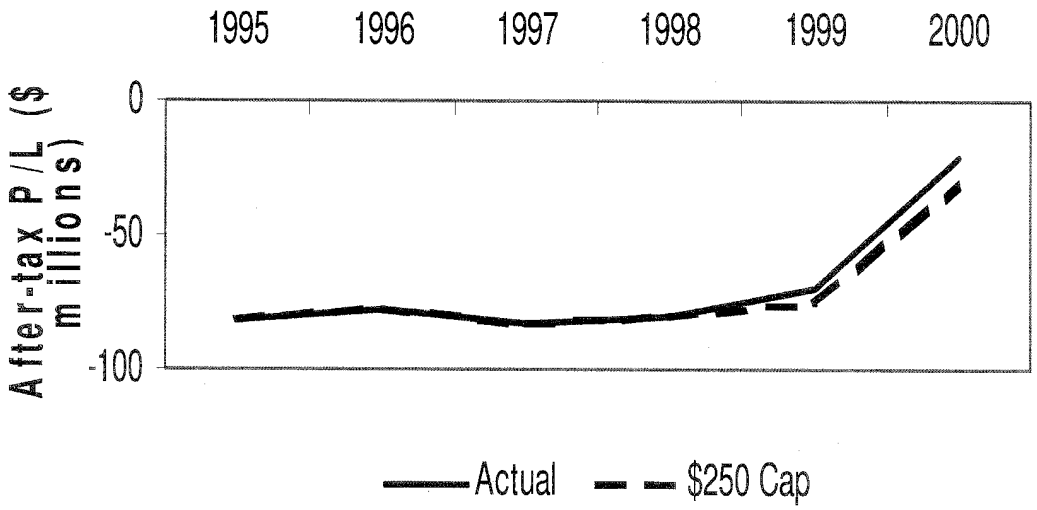
Combined Cycle Annual Profit



Combined Cycle: Cumulative After-tax Profit/Loss



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Load Responsiveness

- 2700 MW of Load theoretically available under the Interruptible Tariffs
- New Load Management Programs Have Been Expensive and Small
  - 100 MW to 300 MW of Shared Savings with IOU's When Prices Exceed $250/MWh
  - 230 MW in CAISO Participating Load Agreement with Capacity Costs of $750/MWh and Energy Costs Up to $750/MWh
  - Seldom Used - Most Participants Already Under Interruptible Tariff

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The ISO's Demand Side Program Has Not Been Very Effective

- The proponents of price caps claim that as soon as the demand side is "workably competitive" then there is no need for price caps
- But if ISO sets the caps too low it will not get demand response
- The utilities have up to 2700 MW of available interruptible load, yet only a small fraction responds when called (600 MW)
- Uncut loads willingly lose value of up to $1,500 per MWh
- Thus, during times of scarcity, the value of energy is at least $1,500 per MWh

Price Controls are Detrimental to Investment and Other Markets

- Merchant generation subject to volatile commodity prices -- caps will inhibit investment
- Creates asymmetry between load response and generation
- Suppliers will sell outside California where markets are more predictable and prices are higher.
- Because of the interdependent linkages in California's electric market, cannot change one aspect of structure without impacting all others
- Uncertainty in the marketplace will dry up the growing forward markets

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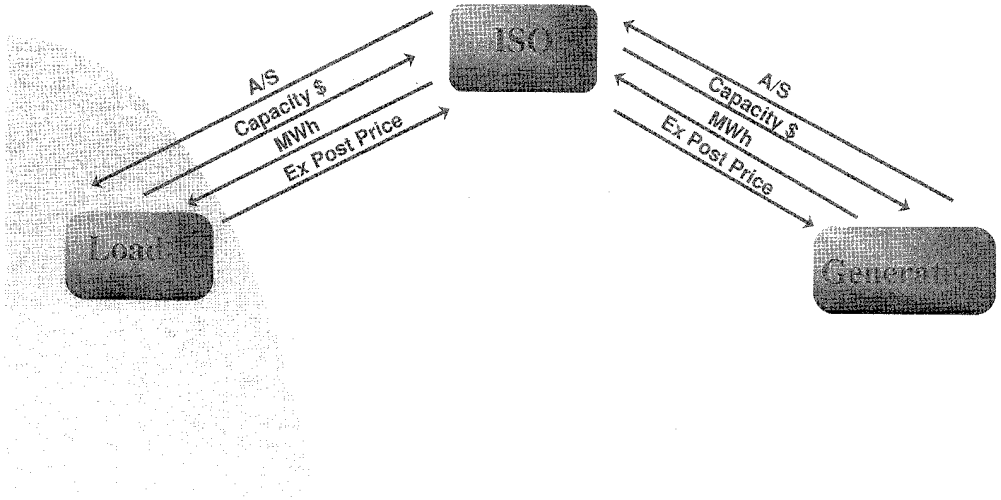
Background
ISO and PX Market

California Independent System Operator

- Real Time Energy Market - Based on complex computer model
- Day ahead and hour ahead ancillary service market
- Day ahead and hour ahead transmission market

Linkages in California's Electric Markets



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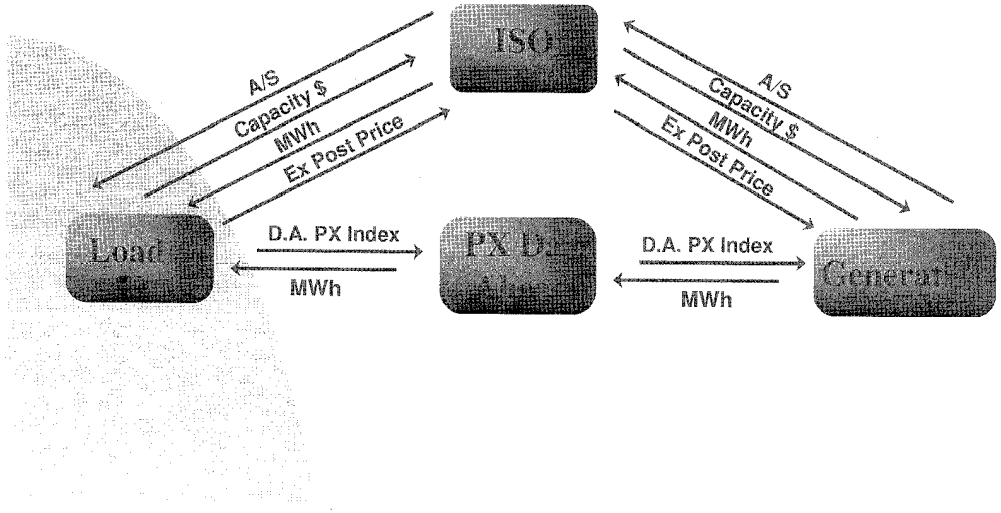
California Power Exchange

- Day Ahead Energy Market - Single price auction based on cross of supply and demand bids.
- IOUs all energy purchased from this market deemed "prudent" by PUC.

Linkages in California's Electric Markets



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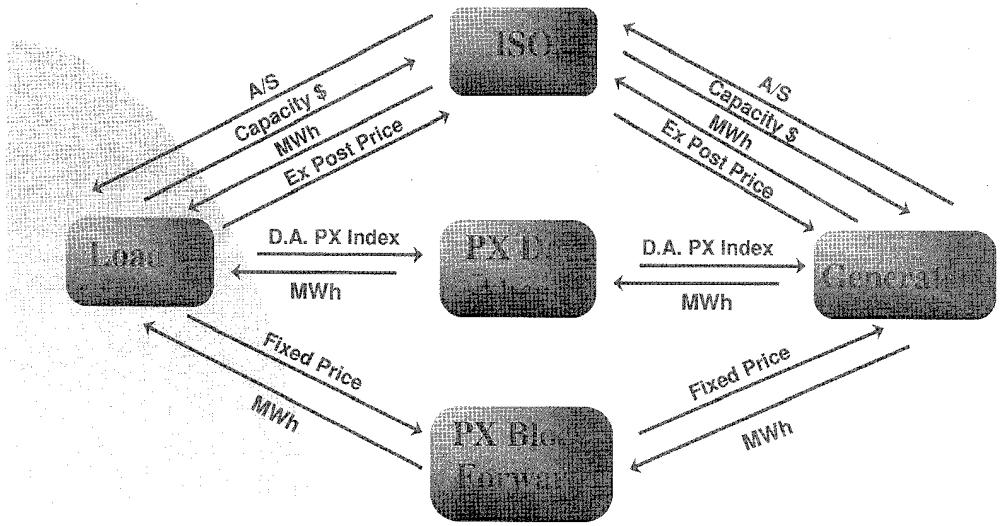
Linkages in California's Electric Markets



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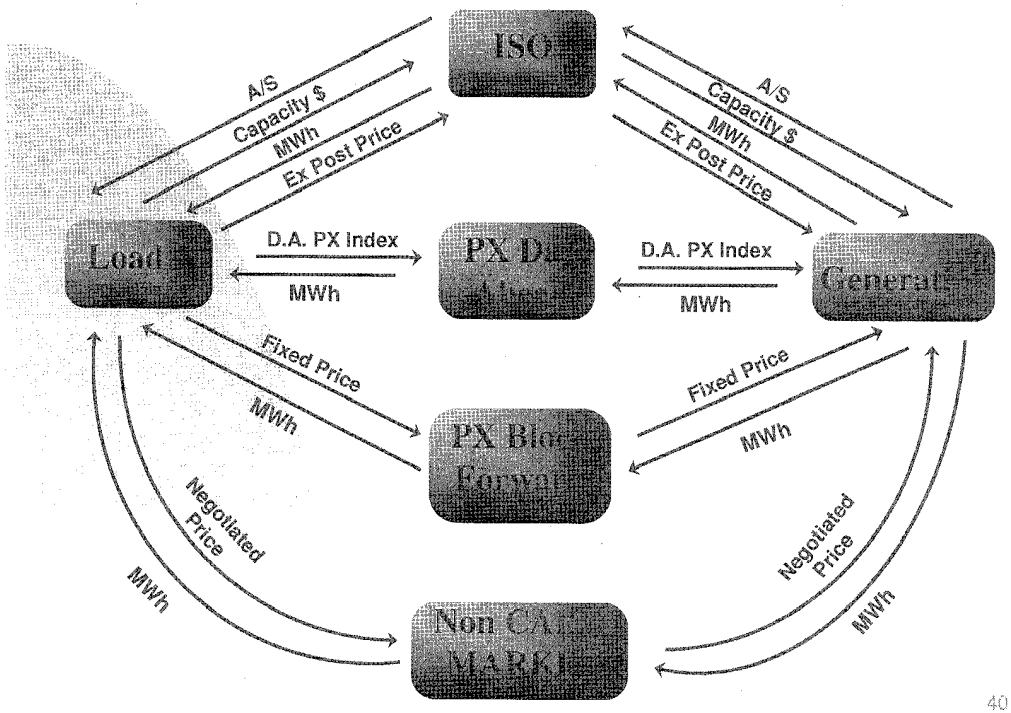
Linkages in California's Electric Markets



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California Regulatory Overlay

- Assembly Bill 1890
  - Provided mechanism for recovery of stranded costs.
  - Required divestiture of thermal generating resources.
  - Froze IOU retail rates until either April of 2002 or stranded costs are recovered, whichever is sooner.

Recent California Events

- CPUC limits on hedging in the "forward" (longer term) market
- 8/03/00 CPUC allowed PG&E and SoCal Edison to do bilateral deals in forward market (subject to previously established hedging limits) if PX schedules the deal
- CPUC performs expedited, upfront prudence review
- CPUC considering similar proposal by SDG&E

Retail/Wholesale Market Interaction

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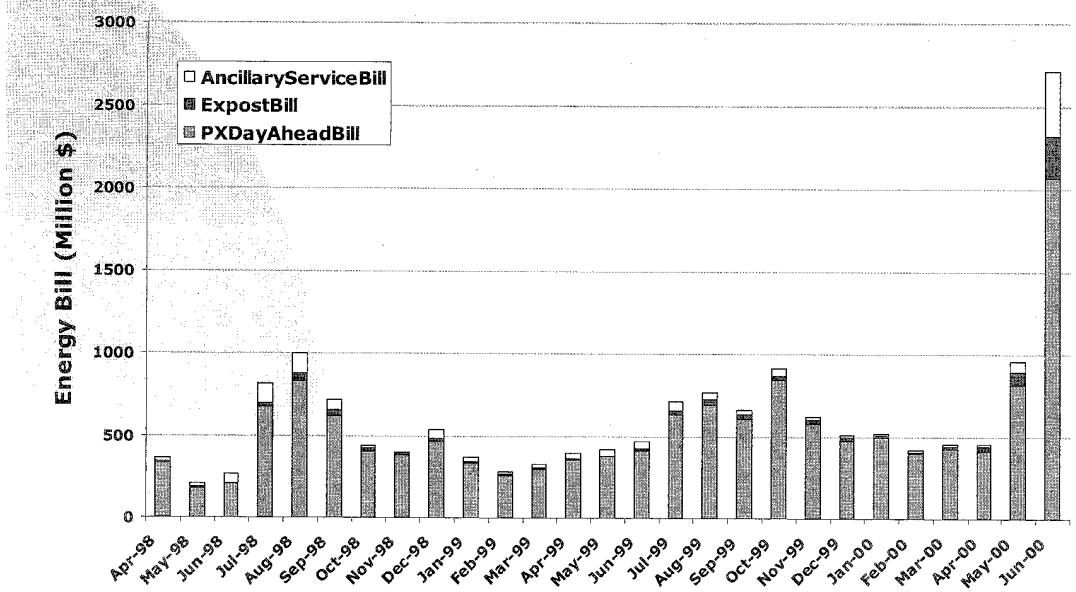
Are Retail Prices High and Do They Indicate Wholesale Market Failures?

- DMA admits that there is workable competition for 98-99% of the total annual hours
- It assumes that market power is present when bids exceed only short run marginal cost rather than considering long term returns, or other market power indices.

Monthly Energy Bill



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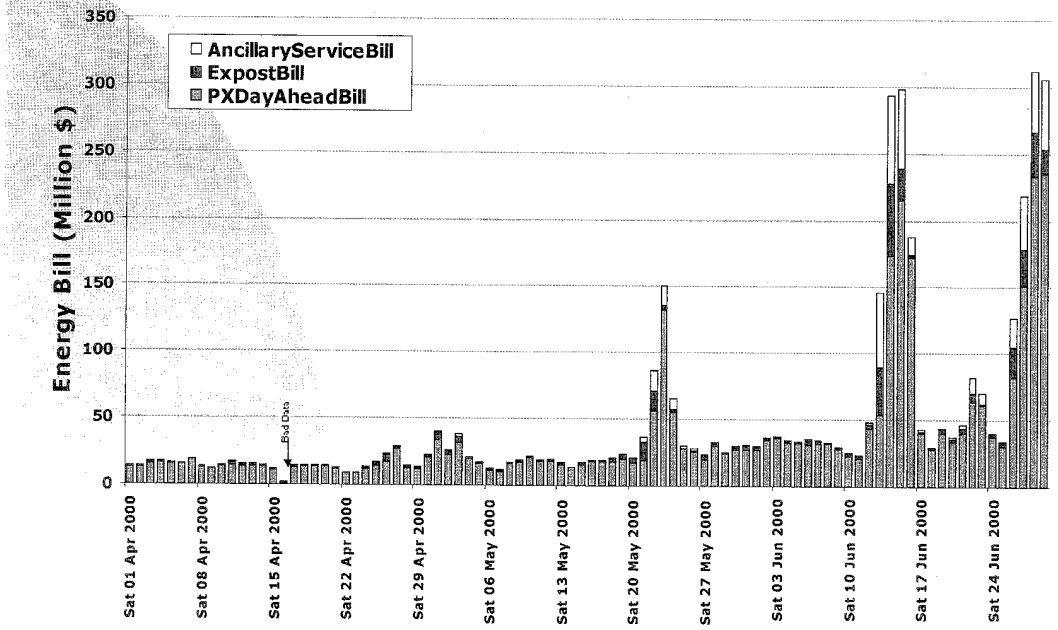
Daily Energy Bill



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Do these Prices Warrant Wholesale Market Intervention?

- Overall, even with scarcity conditions, retail prices have not been significantly increased due to wholesale competition in California (for SDG&E 10-20 percent annual increase, possible 10-20% overall decrease when adjusted for SDG&E rebate)
- Is it appropriate to institute wholesale price controls to mitigate retail price risk?
- Wholesale futures prices are behaving rationally regardless of these short term retail prices

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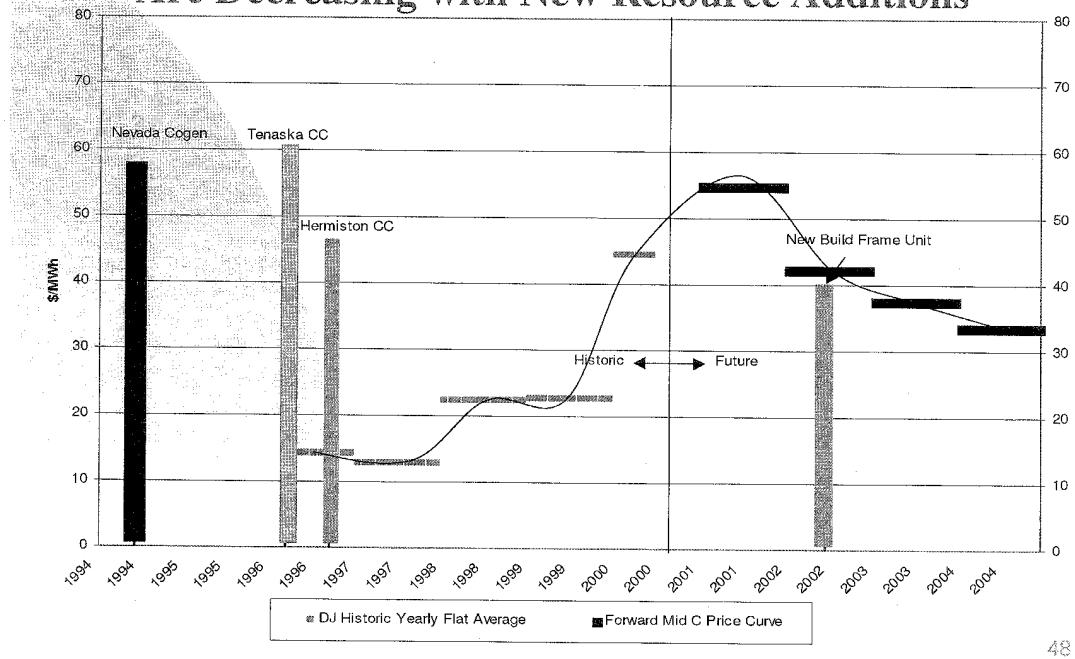
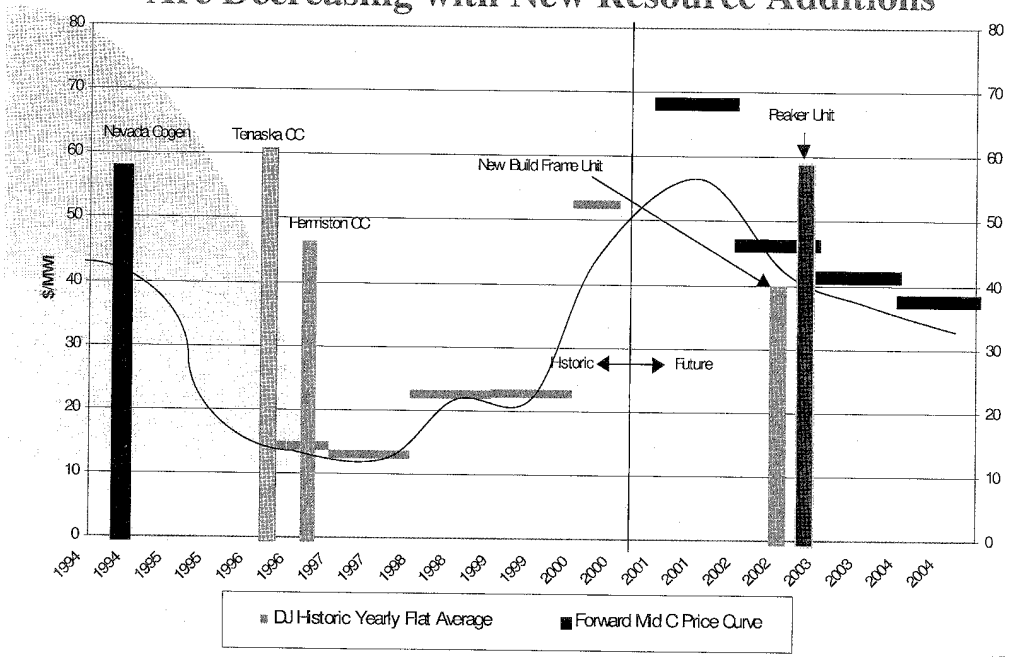
The Market Assumes That Wholesale Prices Are Decreasing with New Resource Additions



The Market Assumes That Wholesale Prices Are Decreasing with New Resource Additions

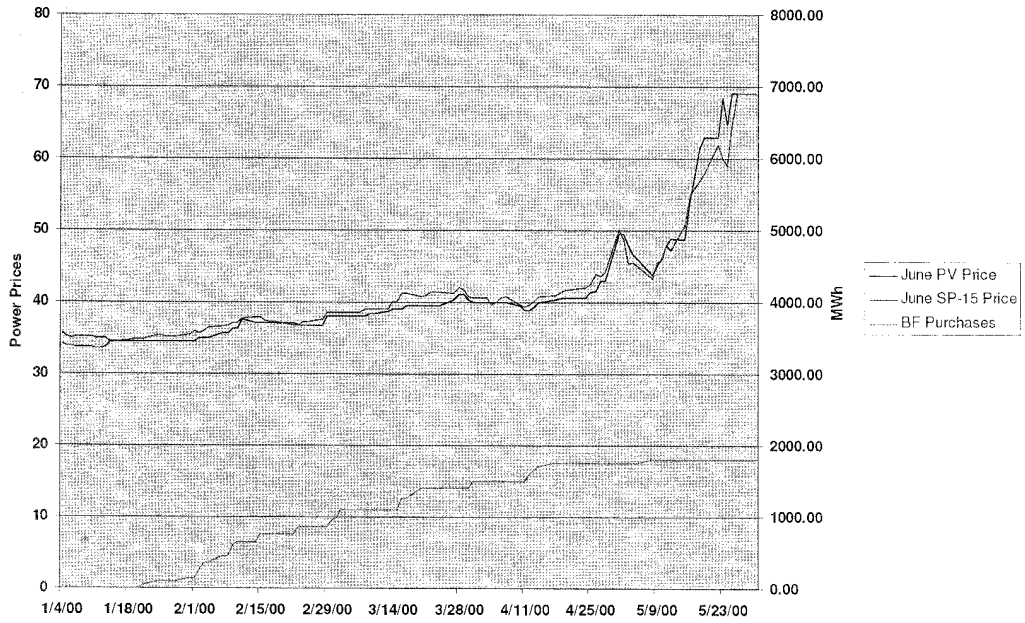


*Estimates for QF contract prices based on Lawrence Berkeley Laboratory Report published in 1996.

Lack of IOU Hedging Has Distorted Price Impacts

- The IOUs had a choice of buying their power in the PX Block Forward, PX Day Ahead, PX Day Of, and CAISO Ex Post
- Hedging limits prevented some purchases of forward energy
- IOU claims notwithstanding, there *have* been significant opportunities to hedge forward prices
  - ~ 1800 MW in entire PX block forward for SP15 in June, 2000
  - Only ~800 MW for SCE out of 2,200 MW authorized
  - Clear market signals to hedge
- Fear of prudence review kept IOUs from hedging the risk of day ahead and real time prices

June SP15 Block Forward Purchases vs. Power Prices



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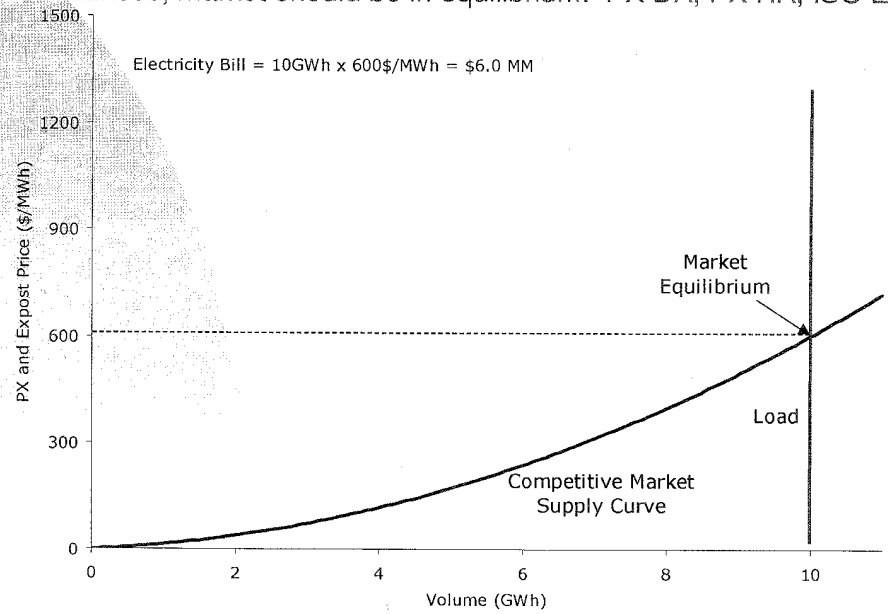
Stranded Cost Recovery Incents IOUs to Underschedule in the Forward Market and Buy in the Spot Market

- CTC payments can theoretically be increased by underscheduling demand in the PX Day ahead markets
- But, underscheduling demand increases ISO prices and reduces reliability
  - ~ 30% of ISO load in real time market on 06/14/00
  - Only 100 MW of blackouts--a remarkable achievement

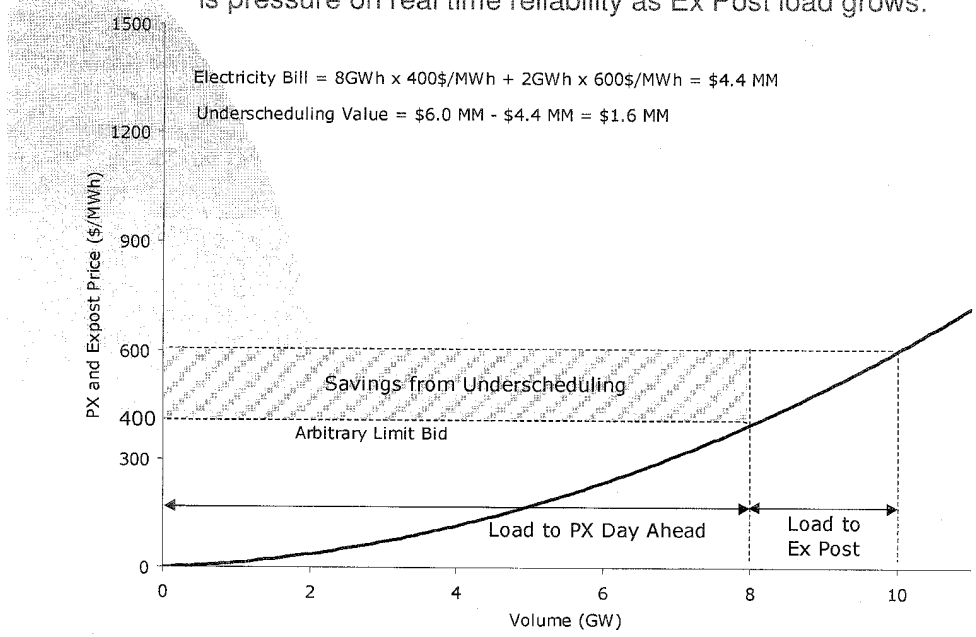
Gross Underscheduling of Load Is a Real Problem

If all power scheduled in PX Day Ahead market, except for small imbalances, market should be in equilibrium: PX DA, PX HA, ISO Ex Post



Gross Underscheduling of Load Is a Real Problem

In actual fact, there is an incentive to underschedule, but consequence is pressure on real time reliability as Ex Post load grows.



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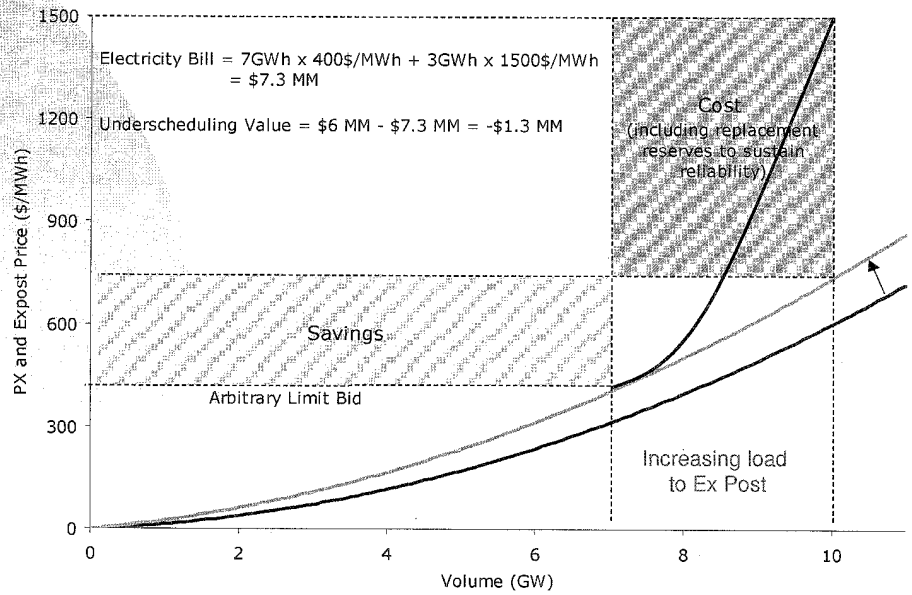
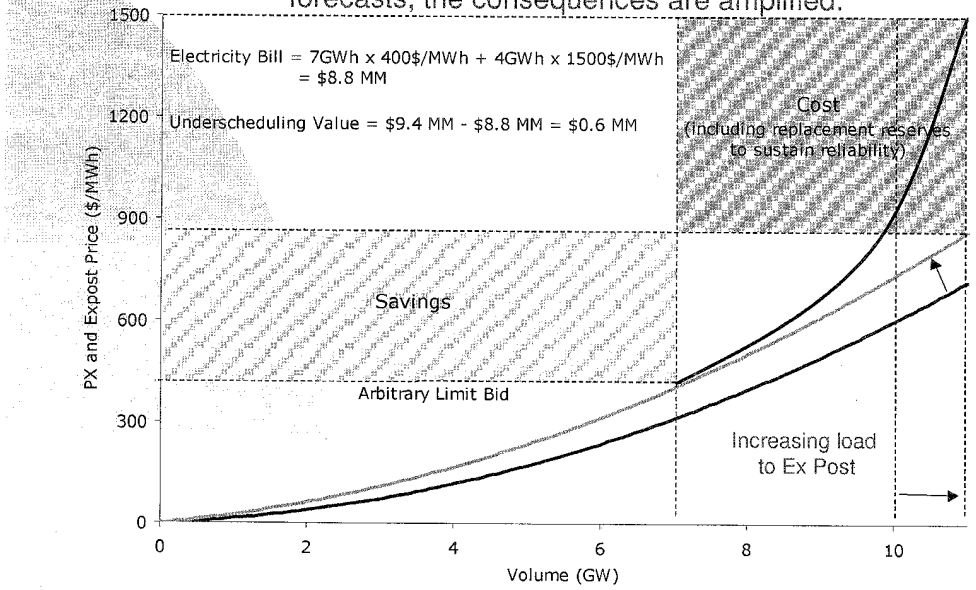
Gross Underscheduling of Load Is a Real Problem

But when there is massive underscheduling in a tight supply market, the ISO may have to take drastic action.



Gross Underscheduling of Load Is a Real Problem

And, when load is growing faster than forecasts, the consequences are amplified.



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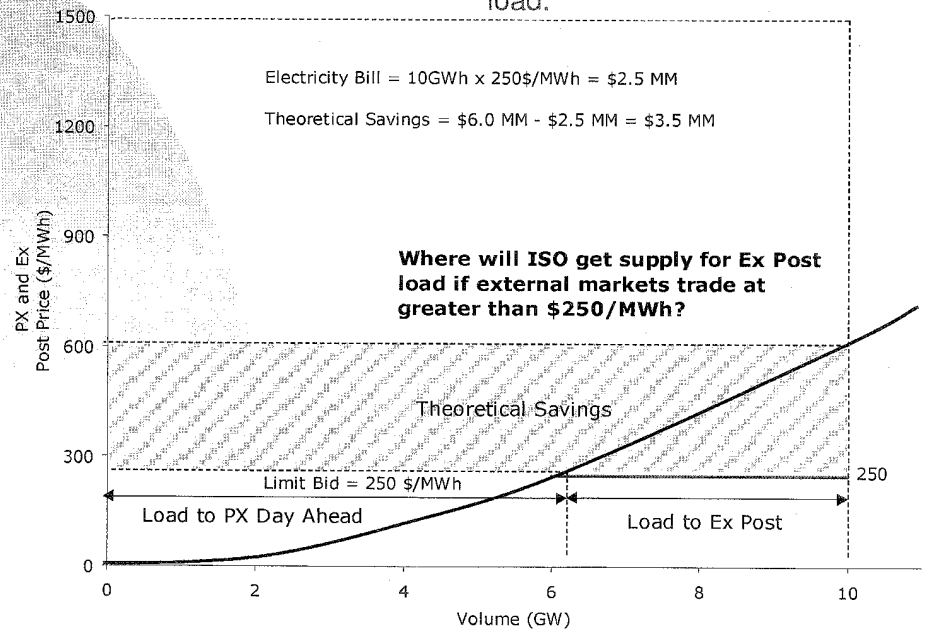
Gross Underscheduling of Load Is a Real Problem

When price caps are reduced to $250/MWh in a scarce supply market, ISO may not be able to maintain reliability due to magnitude of Ex Post load.



Underscheduling's Effects on Reliability Are Observable

- Stage 1 Emergency
  - In Anticipation of Low Reserves
  - Users Asked to Voluntarily Reduce Consumption
  - 15 Times From May 22 to August 5
- Stage 2 Emergency
  - Reserves Fall Below 5%
  - 2700 MW of Interruptible Load Curtailed
  - 9 Times From May 22 to August 5
- Stage 3 Emergency
  - Reserves Fall Below 1.5%
  - Firm Load Cut - Rolling Blackouts
  - 0 Times From May 22 to August 5

Wholesale Market Remedies Necessary Now

- Analyze whether there are market power concerns associated with times of scarcity and then determine appropriate level of price caps
- Publicize market information
- Encourage structure/ technological innovation to enhance demand side participation
- Don't mistake San Diego's failure to hedge as failures in the wholesale market
- Decide whether FERC has a role in the underscheduling issue: Are the California utilities exercising monopsony power by underscheduling load into the PX day ahead market?

ISO Should Do More Rigorous Market Power Analysis

- The Market Analysis Unit report and the UC Energy Institute Report wrongly uses pricing above short term marginal cost to conclude that there is market power
- Some market power analysis failed to take into consideration changes in supply and demand like the decrease in hydro generation
- To distinguish market power from scarcity, FERC should instruct the ISO to use rigorous analytical measures to determine market power
- Under such measures Enron does not have market power

ISO Should Allow Scarcity Rents

- At points of scarcity (e.g., at Stage 2 when you're getting low on reserves and you're cutting load) marginal cost is no longer a reasonable price.
- Rather when you reach scarcity you should price scarcity rents at the value of energy (e.g., $1,500 as illustrated in the interruptible market)

To Investigate the Source of High Prices FERC Should Review:

- High gas prices
- Below normal Hydro
- Lack of NOx credits
- High demand
- How many MWs did the CA ISO procure during the Summer 2000 compared with 1999?
- Has PG&E changed its bidding behavior associated with its Hydro facilities in 2000?
- Were baseload facilities operated differently in 2000 than in 1999?

To Investigate the Source of High Prices FERC Should Review (Continued)

- Were any generation plants off-line due to unplanned maintenance during Summer 2000?
- Were other Western power markets prices higher (year-on-year)?
- What options did SDG&E have to "hedge" its retail rates?
- What were prices in the CAL PX block forward market on Jan 15, 2000 and May 15, 2000?
- FERC and the ISO should consider the regional impacts of any price caps implemented in California, such as prices not corresponding to flows

Other Market Growing Pains

- Only a limited number of out-of state participants can access spin and non-spin markets
- Rate freeze prevents consumers from receiving price signals (I.e., some amount of load increase is illogical behavior)
- Intrazonal congestion not explicitly priced--Socialized across all loads
- Complex computer model used to price transmission
- Relatively little transmission available in forward markets
- Stakeholder board subject to political pressure
- Forward market liquidity has evaporated due to price cap changes

We Do Not Have All the Answers. Why?

- Much information that is necessary to analyze the California PX and ISO markets is not available to markets participants
- We believe that California can significantly enhance competition in its electricity markets if this information is made available

Why Would Information Make the Market More Competitive?

- Publishing price information would provide better price signals producing a more efficient market
- Publishing generation and load information would remove competitive advantages held by monopsony load servers and generators with a large percentage of the market
- Publishing transmission information would remove the ATC knowledge advantage retained by grandfathered transmission contract holders
- More information would help the market to self-police

Generation and Load Information That Should be Available

- "After the fact" actual meter information depicting actual unit-by-unit production and consumption within each zone.
- Unit outage information showing planned and forced outages.
- Water levels, or hydro outputs. Weekly/monthly information.
- Data on significant unit outages etc. in the peak prices hours in question.
- Calls by the ISO on plants with Reliability Must Run contracts.

Energy and Ancillary Service Price Information That Should be Available

- All bid information in both Day Ahead and Hour Ahead Markets, including generation and load, energy and ancillary services
- The information for these markets should include: initial preferred schedules, final schedules and the BEEP stack, all day ahead load and generation bids by Scheduling Coordinator

Transmission Information That Should be Available

- The information should include adjustment bids, day ahead schedules, hour ahead schedules, real time adjustments, actual flows, and transmission availability by category of ownership
- This information should be provided for all transmission lines
- Significant Intra-zonal congestion by transmission path
- Data should be differentiated by existing and new, firm use transmission contracts

When Should This Information Be Available?

- The information listed above ought to be provided as close to "real time" as possible.
- At a minimum it ought to be provided to the market within 24 hours.

What To Do About Western Wholesale Markets?

August 25, 2000

Tim Belden
Enron North America
West Power

Summary

- High prices in peak periods are the result of scarcity and are necessary to incent needed generation investment
- California Retail/Wholesale Market Interaction
  - Retail customers are benefiting from the low prices during shoulder months caused by wholesale competition
  - The major problem is in the retail market where high peak period wholesale prices have not been mitigated by forward purchases
  - Underscheduling in forward market causes high demand and reliability problems during real time

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Summary (Continued)

- Some wholesale market remedies are necessary now
  - The FERC should analyze whether there are Market Power Concerns Associated with Times of Scarcity and then determine appropriate level of Price Caps
  - Publicize Market Information
  - Encourage structure/ technological innovation to enhance demand side participation

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Agenda

- Market Fundamentals Indicate Scarcity Exists
- Supply Side and Demand Side Economics
- Retail Design Issues
- Wholesale Market Remedies

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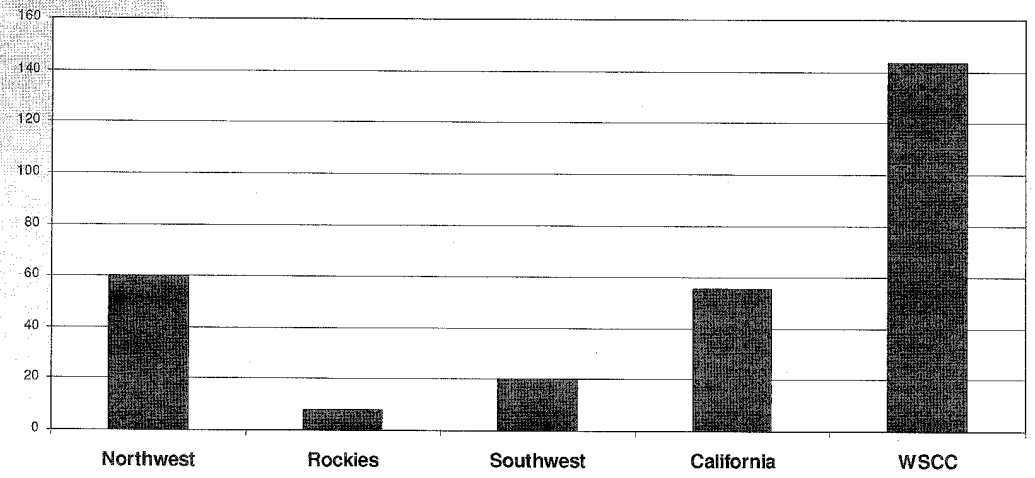
Western Supply and Demand Fundamentals

WSCC Loads (GW)

California is not an island and cannot develop a self-contained solution.



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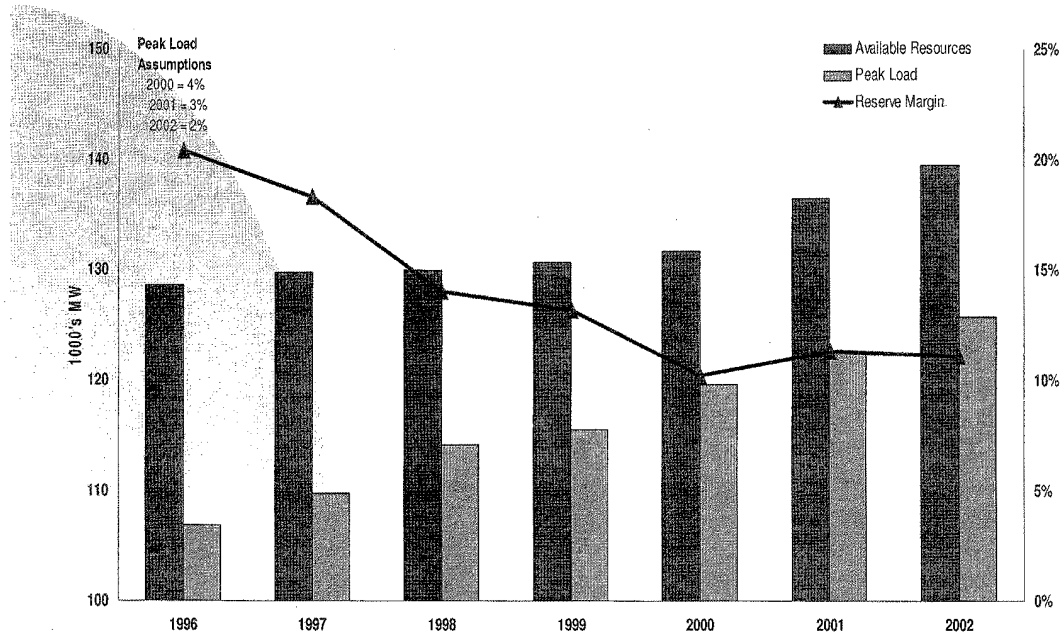
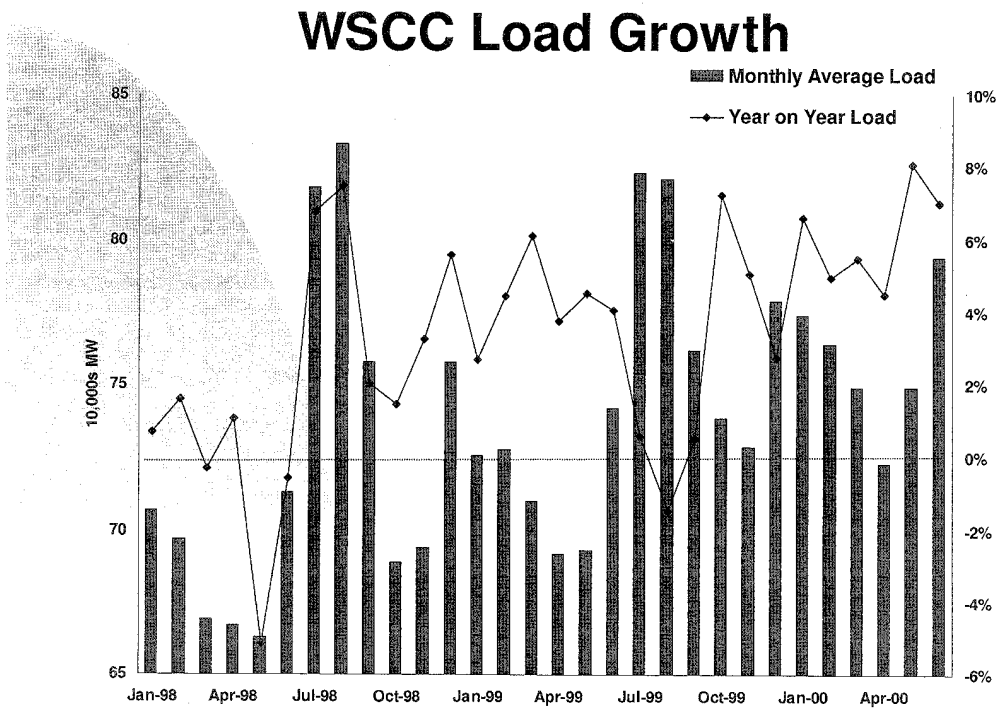
WSCC Resources and Loads



Base data from WSCC. Adjustments made by Enron based on verifiable data inaccuracies.



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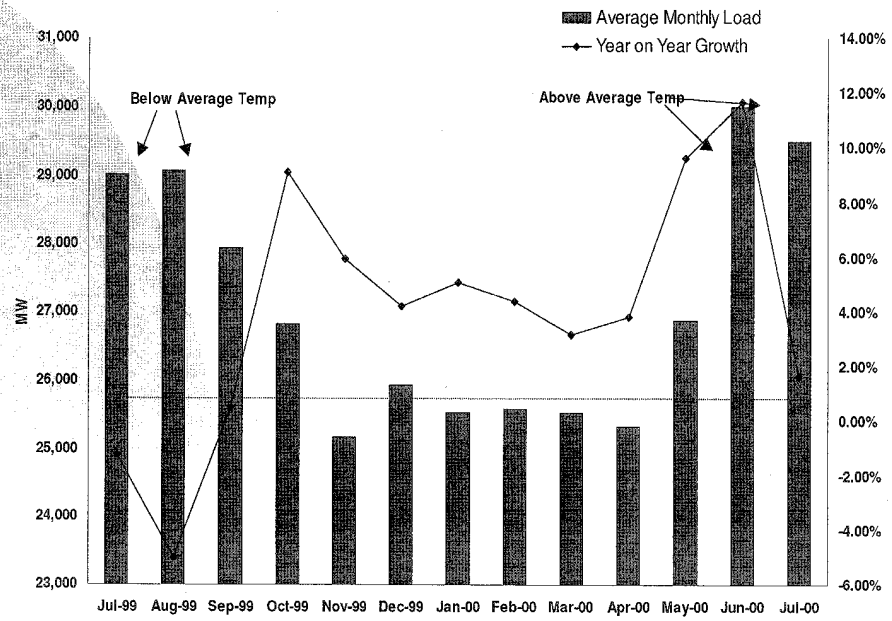
California ISO Load Growth

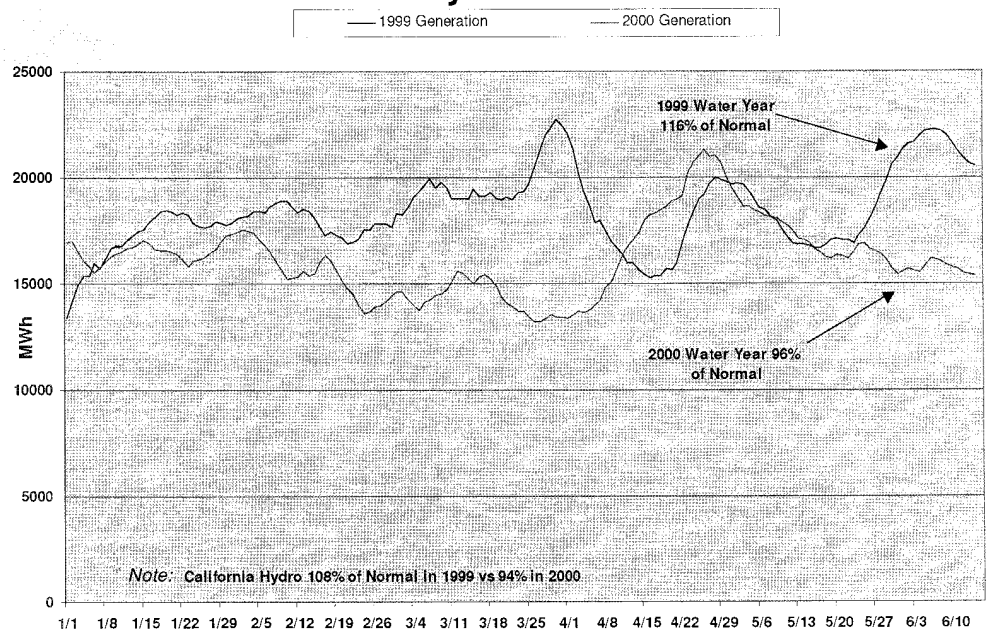


Has Recent Unusually Strong Hydro Fooled Us?

Volume Runoff Percent of Normal

	Columbia River	California
2000	93%	94%
1999	116%	108%
1998	98%	153%
1997	152%	84%
1996	138%	129%

PNW Hydro Generation



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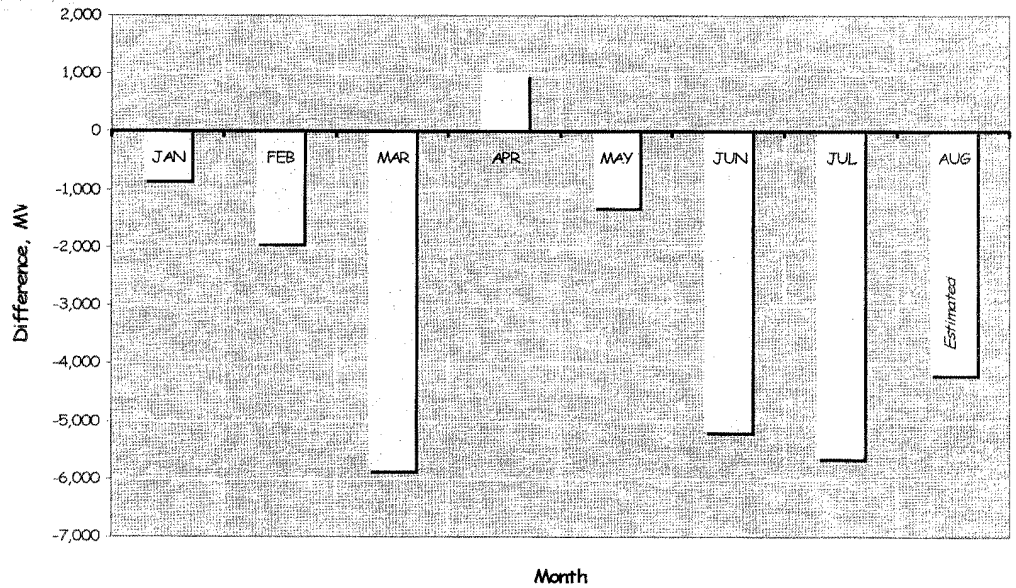
Pacific Northwest 2000 Hydro Production Relative to 1999



WSCC Capacity Additions

	Summer 2000	Summer 2001	Summer 2002
Northwest	7	760	851
California	-0-	1000	2648
Southwest / Rockies	908	2390	692
Total	915	4150	4191
Estimated Load Growth (Assumes 3% Escalation)	(3600)	(3708)	(3819)

In Sum, Scarcity is Real - Generation is Needed

- Scarcity is real
- Energy prices driven by scarcity
- New generation or demand-side resources are required

ECu000060626

Current Supply/Demand Economics

ECu000060627

Power Economics

- Power is a Bust and Boom Commodity -- Merchant Generators Lose Money in Some Years and Make it Up During Times of Scarcity
- California Demand Side Resources are Far More Expensive than Supply Side Resources
- Demand Side and Supply Side Resources Should Receive Symmetrical Treatment with Respect to Price Signals

ECu000060628

Peaker Plant Economics

- Technology: GE LM 6000
- Fuel: Natural Gas
- Heat Rate: 10,000 Btu/Kwh
- Capacity: 48 MW
- Capital Structure:
  - 60% Debt @ 9%
  - 40% Equity @ 18%
  - 15 Year Amortization
- Total Cost to Build: $27 million
- Annual Capital Recovery: $3.7 million
- Annual Fixed O&M: $1.5 million
- Annual Total: $5.2 million

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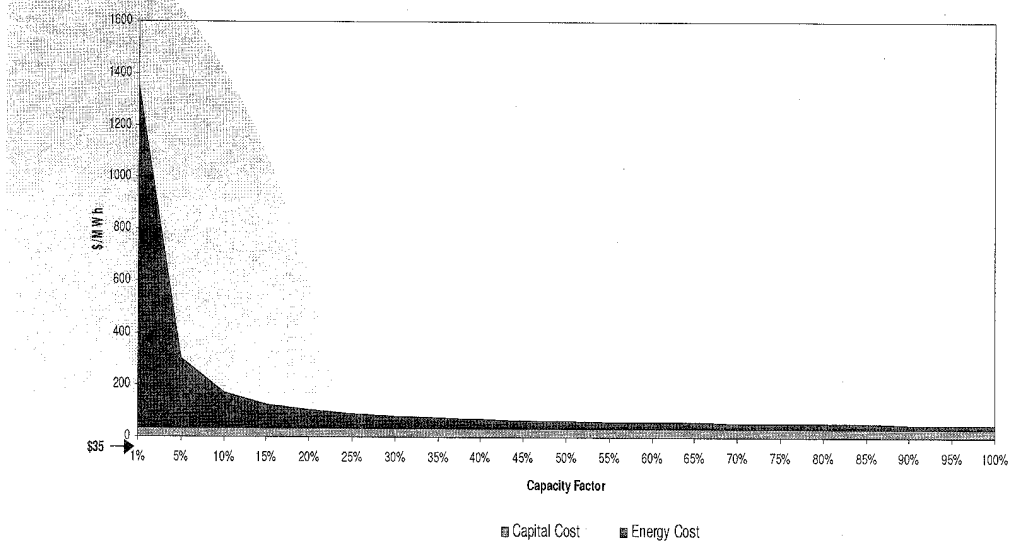
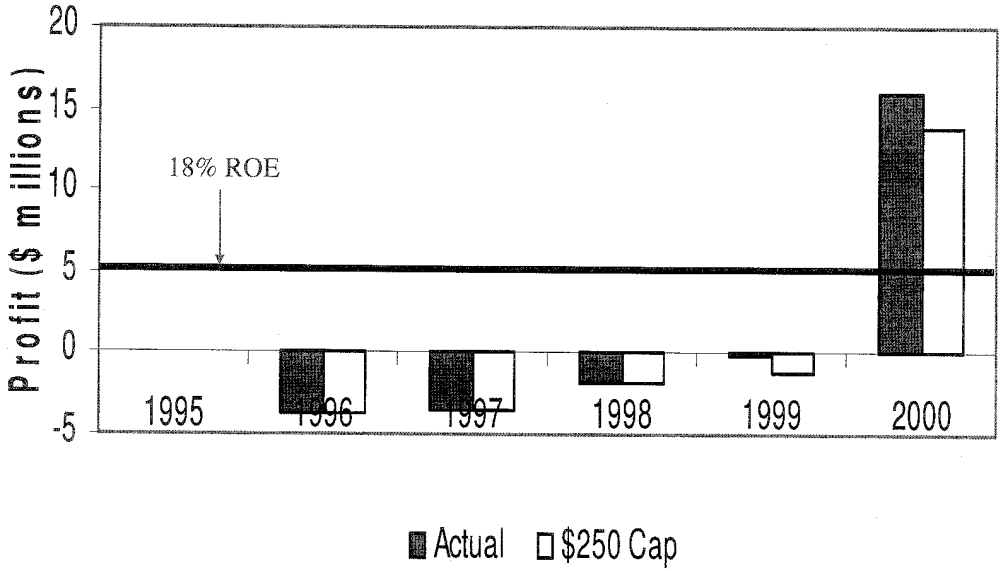
Peaker Plant Cost-to-Build



LM6000 Annual Profit



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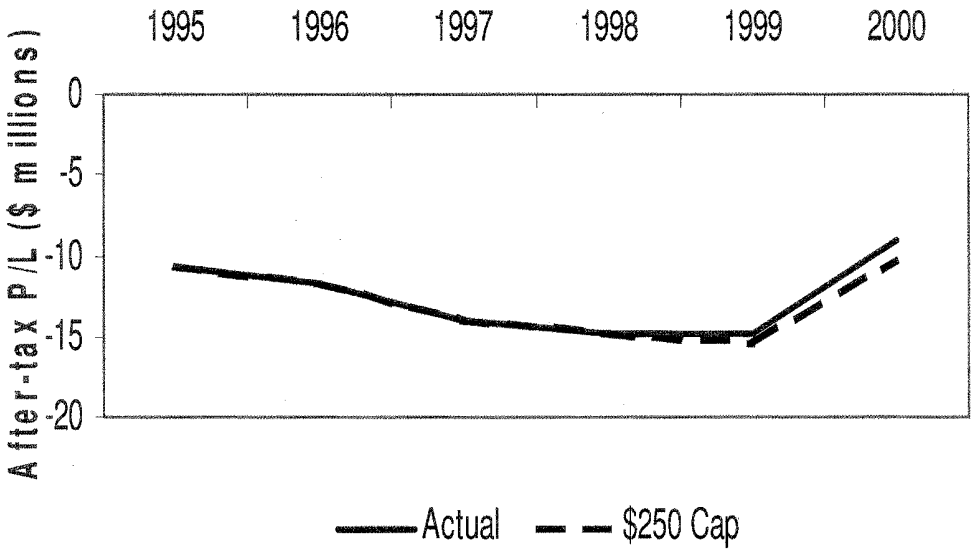
LM6000: Cumulative After-tax Profit/Loss



Baseload Plant Economics

Technology: Combined Cycle	GE Frame 7FA
Fuel:	Natural Gas
Heat Rate:	7,100 Btu/Kwh
Capacity:	280 MW
Capital Structure:	
◆ 50% Debt @ 9%	
◆ 50% Equity @ 15%	
◆ 15 Year Amortization	
Total Cost to Build:	$180 million
Annual Capital Recovery:	24 million
Annual Fixed O&M:	3 million
Annual Total:	$27 million

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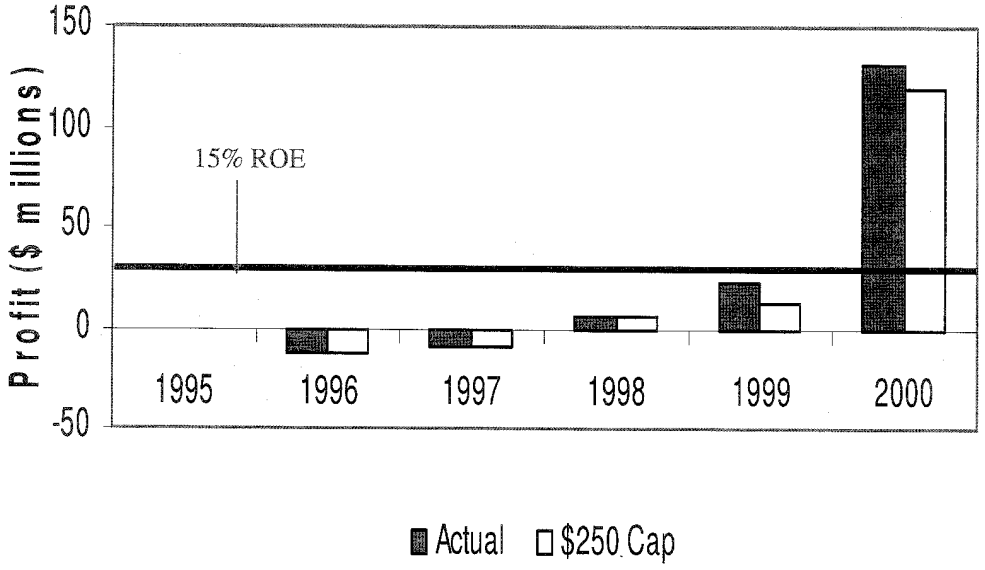
Combined Cycle Annual Profit



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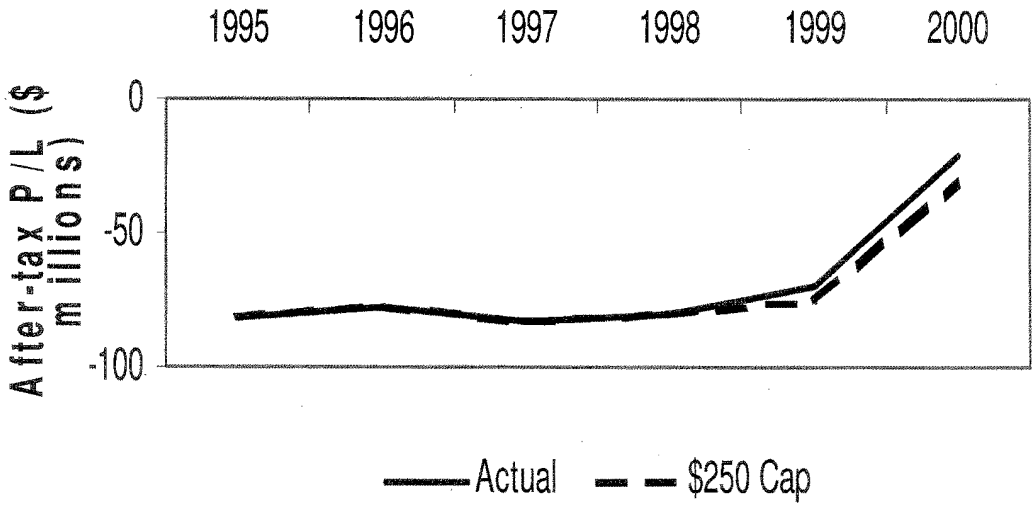
Combined Cycle: Cumulative After-tax Profit/Loss



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Load Responsiveness

- 2700 MW of Load theoretically available under the Interruptible Tariffs
- New Load Management Programs Have Been Expensive and Small
  - 100 MW to 300 MW of Shared Savings with IOU's When Prices Exceed $250/MWh
  - 230 MW in CAISO Participating Load Agreement with Capacity Costs of $750/MWh and Energy Costs Up to $750/MWh
  - Seldom Used - Most Participants Already Under Interruptible Tariff

Source: ISO DMA August 10 Report

The ISO's Demand Side Program Has Not Been Very Effective

- The proponents of price caps claim that as soon as the demand side is "workably competitive" then there is no need for price caps
- But if ISO sets the caps too low it will not get demand response
- The utilities have up to 2700 MW of available interruptible load, yet only a small fraction responds when called (600 MW)
- Uncut loads willingly lose value of up to $1,500 per MWh
- Thus, during times of scarcity, the value of energy is at least $1,500 per MWh

Price Controls Will Perpetuate Scarcity

- Power plants are needed; Demand is still not very price responsive
- Operating costs of plants are increasing
  - Gas prices high
  - Gas generally is on the Margin in WSCC (I.e., Gas-fired generation sets the electricity generating market price)
- Power plant economics will keep generators from investing in generation if they anticipate price cap
- In state and out of state generation will be incented to sell out of state

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Price Controls are Detrimental to Investment and Other Markets

- Merchant generation subject to volatile commodity prices -- caps will inhibit investment
- Creates asymmetry between load response and generation
- Suppliers will sell outside California where markets are more predictable and prices are higher.
- Because of the interdependent linkages in California's electric market, cannot change one aspect of structure without impacting all others
- Uncertainty in the marketplace will dry up the growing forward markets

Retail Market Design Issues

ECu000060640

Retail Issues

- SCE and PG&E Customers Receive No Price Signals Due to CTC Balancing Accounts.
- SDG&E Customers Entered Volatile Short Term Commodity Markets Without Knowing About Risk and Without SDG&E Hedging For Them.
- Limits on IOU Forward Hedging Forces Large Volumes Into Day Ahead and Real Time Markets Which Contributes to Volatility.
- CTC Recovery Mechanism Incents IOU's to Take Large Volumes to Real Time Market.

ECu000060641

Lack of IOU Hedging Has Distorted Price Impacts

- The IOUs had a choice of buying their power in the PX Block Forward, PX Day Ahead, PX Day Of, and CAISO Ex Post
- Hedging limits prevented some purchases of forward energy
- IOU claims notwithstanding, there *have* been significant opportunities to hedge forward prices
  - ~ 1800 MW in entire PX block forward for SP15 in June, 2000
  - Only ~800 MW for SCE out of 2,200 MW authorized
  - Clear market signals to hedge
- Fear of prudence review kept IOUs from hedging the risk of day ahead and real time prices

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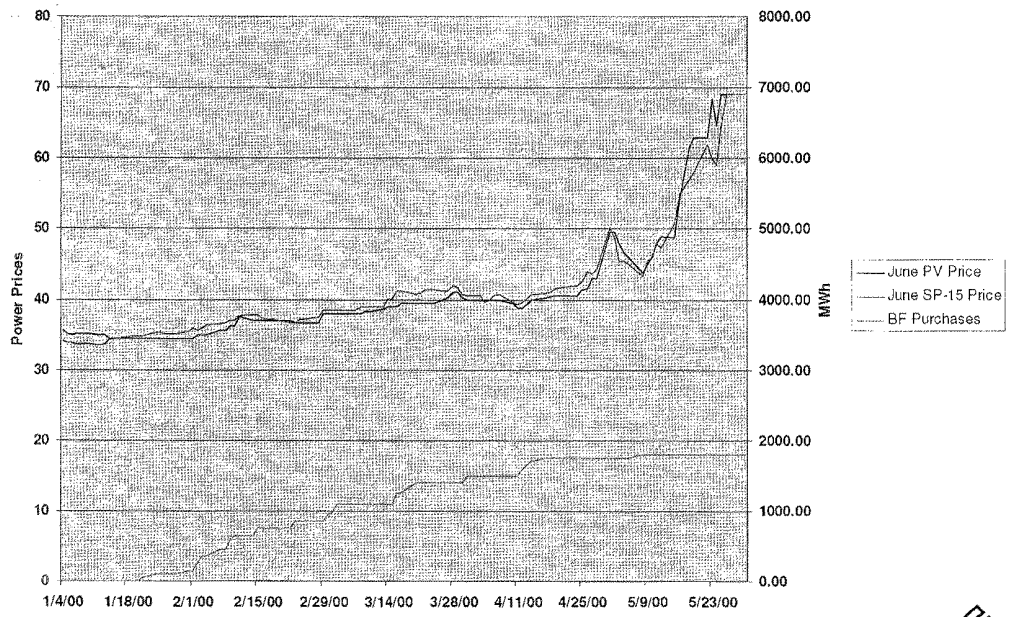
June SP15 Block Forward Purchases vs. Power Prices



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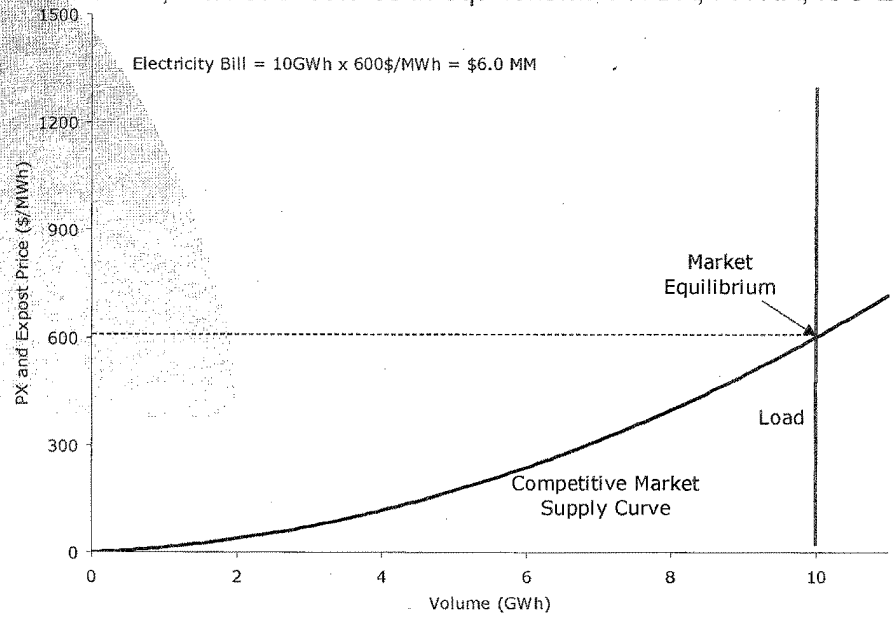
Stranded Cost Recovery Incents IOUs to Underschedule in the Forward Market and Buy in the Spot Market

- CTC payments can theoretically be increased by underscheduling demand in the PX Day ahead markets
- But, underscheduling demand increases ISO prices and reduces reliability
  - ~ 30% of ISO load in real time market on 06/14/00
  - Only 100 MW of blackouts--a remarkable achievement

ECu000060644

Gross Underscheduling of Load Is a Real Problem

If all power scheduled in PX Day Ahead market, except for small imbalances, market should be in equilibrium: PX DA, PX HA, ISO Ex Post



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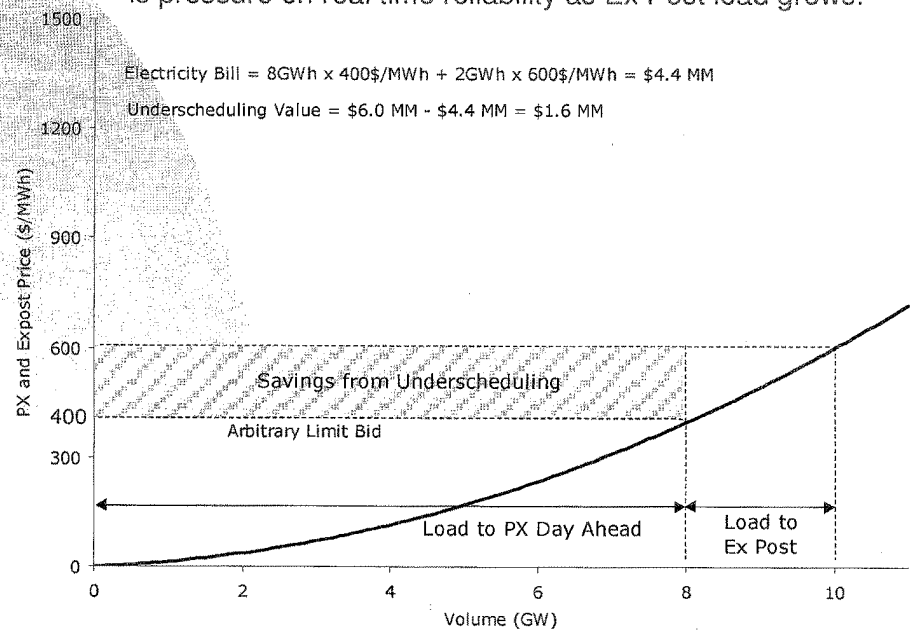
Gross Underscheduling of Load Is a Real Problem

In actual fact, there is an incentive to underschedule, but consequence is pressure on real time reliability as Ex Post load grows.

Electricity Bill = 8GWh x 400$/MWh + 2GWh x 600$/MWh = $4.4 MM

Underscheduling Value = $6.0 MM - $4.4 MM = $1.6 MM



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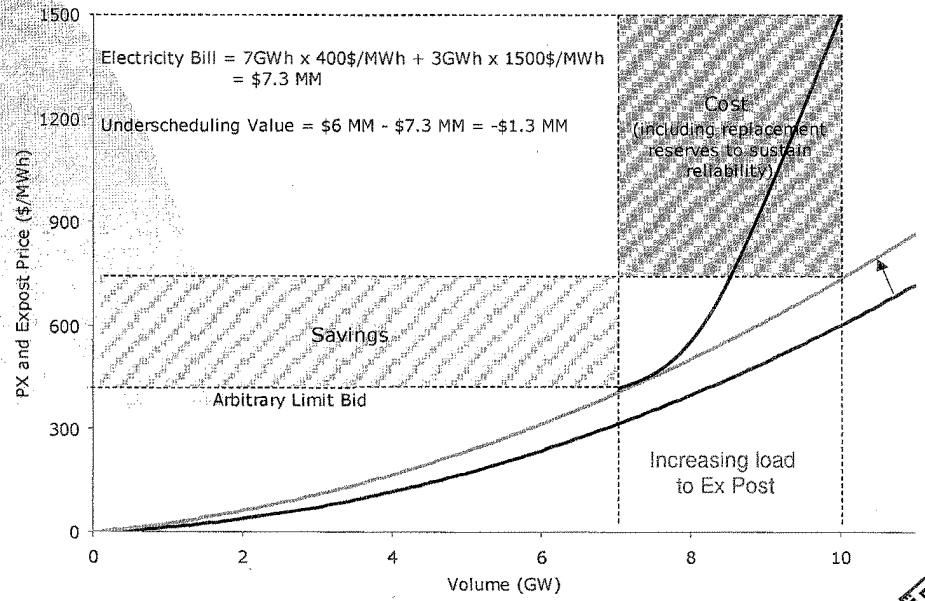
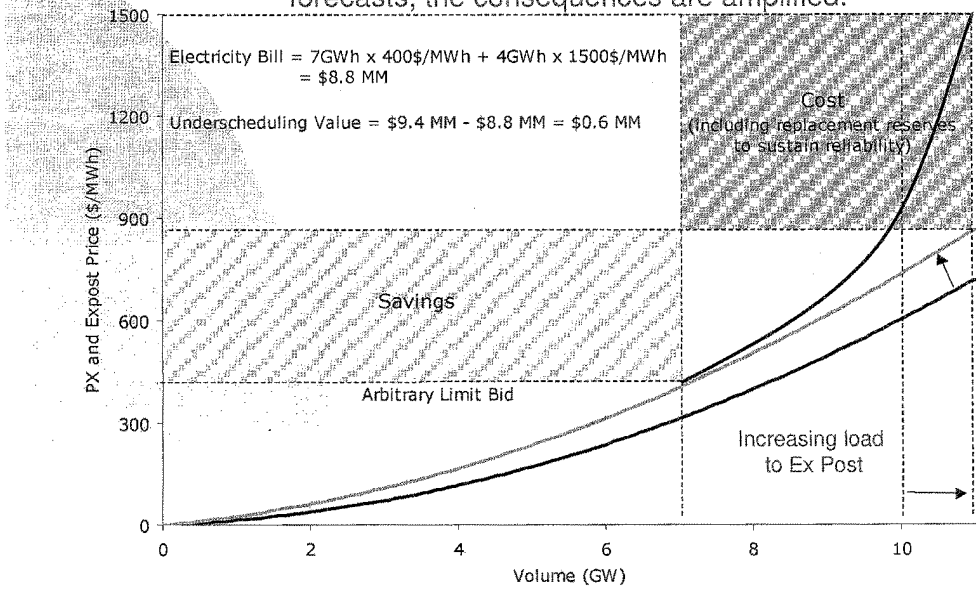
Gross Underscheduling of Load Is a Real Problem

But when there is massive underscheduling in a tight supply market, the ISO may have to take drastic action.



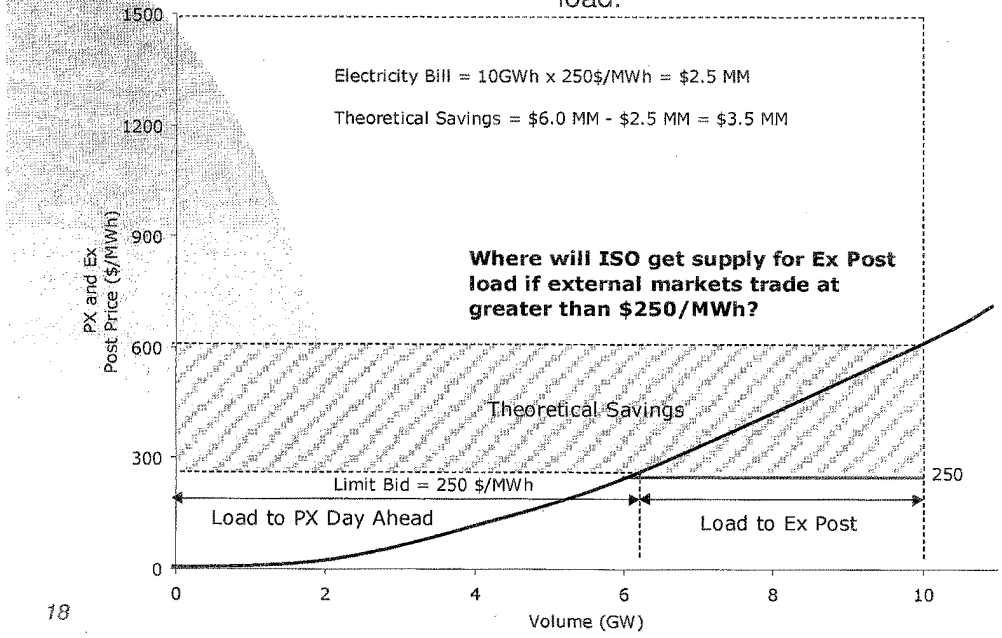
Gross Underscheduling of Load Is a Real Problem

And, when load is growing faster than forecasts, the consequences are amplified.



Gross Underscheduling of Load Is a Real Problem

When price caps are reduced to $250/MWh in a scarce supply market, ISO may not be able to maintain reliability due to magnitude of Ex Post load.



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Underscheduling's Effects on Reliability Are Observable

- Stage 1 Emergency
  - In Anticipation of Low Reserves
  - Users Asked to Voluntarily Reduce Consumption
  - 15 Times From May 22 to August 5
- Stage 2 Emergency
  - Reserves Fall Below 5%
  - 2700 MW of Interruptible Load Curtailed
  - 9 Times From May 22 to August 5
- Stage 3 Emergency
  - Reserves Fall Below 1.5%
  - Firm Load Cut - Rolling Blackouts
  - 0 Times From May 22 to August 5

Retail Design Flaws Are Largest Contributor to Problem

- California should fix its retail problems first.
- Should remove barriers to hedging.
- Should systematically examine relationship between retail and wholesale market design.
- Knee-jerk reactions in wholesale markets will not solve the problem.

ECu000060651

Wholesale Market Issues

- Analyze whether there are market power concerns associated with times of scarcity and then determine appropriate level of price caps
- Publicize market information
- Encourage structure/ technological innovation to enhance demand side participation
- Don't mistake San Diego's failure to hedge as failures in the wholesale market
- Decide whether FERC has a role in the underscheduling issue: Are the California utilities exercising monopsony power by underscheduling load into the PX day ahead market?

ECu000060652

ISO Should Do More Rigorous Market Power Analysis

- The Market Analysis Unit report and the UC Energy Institute Report wrongly uses pricing above short term marginal cost to conclude that there is market power
- Some market power analysis failed to take into consideration changes in supply and demand like the decrease in hydro generation
- To distinguish market power from scarcity, FERC should instruct the ISO to use rigorous analytical measures to determine market power
- Under such measures Enron does not have market power

ECu000060653

Market Power or Scarcity Rents?

- At points of scarcity (e.g., at Stage 2 when you're getting low on reserves and you're cutting load) marginal cost is no longer a reasonable price.
- Rather when you reach scarcity you should price scarcity rents at the value of energy (e.g., $1,500 as illustrated in the interruptible market)

ECu000060654

To Investigate the Source of High Prices FERC Should Review:

- High gas prices
- Below normal Hydro
- Lack of NOx credits
- Planned Outages and Forced Outages in June
- High demand
- Real Capacity Margins in Western Markets
- Relationship between Wholesale Market Design and Retail Market Design
- Relationship between California Market and Other Western Markets

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To Investigate the Source of High Prices FERC Should Review (Continued)

- Were any generation plants off-line due to unplanned maintenance during Summer 2000?
- Were other Western power markets prices higher (year-on-year)?
- What options did SDG&E have to "hedge" its retail rates?
- What were prices in the CAL PX block forward market on Jan 15, 2000 and May 15, 2000?
- FERC and the ISO should consider the regional impacts of any price caps implemented in California, such as prices not corresponding to flows

ECu000060656

We Do Not Have All the Answers. Why?

- ISO and PX have a monopoly on data.
- ISO and PX have monopoly on analysis of market power.
- Transparent markets are preferable to opaque markets. Transparency requires data release.
- Open up the books for all to see.

ECu000060657

Status of Data Release

ECu000060658

ISO GENERATION

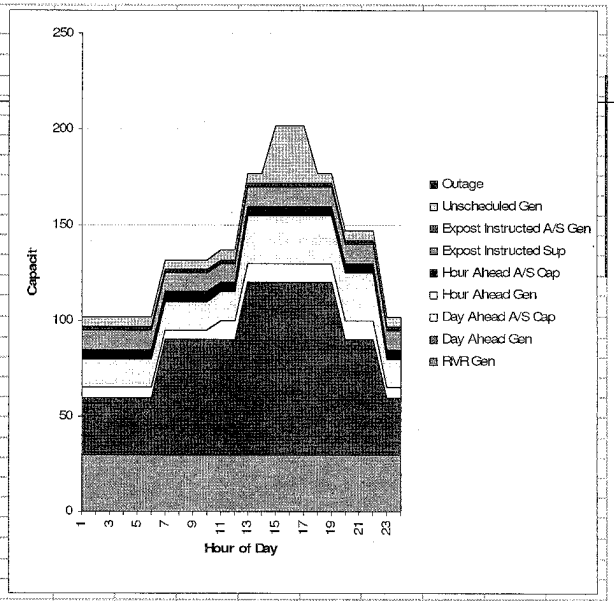
	Allocation*
A	RMR Generation
B	Day Ahead Generation
C	Day Ahead Ancillary Service Capacity
D	Hour Ahead Generation
E	Ancillary Service Hour Ahead Capacity
F	Expost Instructed Supplemental Generation
G	Unscheduled Generation
H	Expost Instructed Ancillary Service Generation
I	Outage/Deration
J	Idle

*Actual Gen = A+B+D+F+G+H

Physical Dimensions
Unit
Plant
Load Zone
Congestion Zone*
System

* Supply and Demand for Capacity, Generation, and Transmission are related at the Congestion Zone Level

Data
Awarded Price-Quantity
Price Quantity Offer Curve



ISO GENERATION

Allocation	Awarded Price-Quantity					Price-Quantity Offer Curve				
	Unit	Plant	Load Zone	Cong Zone	System	Unit	Plant	Load Zone	Cong Zone	System
RMR Generation										
Day Ahead Generation										
Ancillary Service Capacity										
Hour Ahead Generation										
Ancillary Service Hour Ahead Capacity										
Expost Instructed Supplemental Generation										
Unscheduled Generation										
Expost Instructed Ancillary Service Generation										
Outage/Deration										
Idle										

Possible
Released
Partially Released

ISO LOAD

Allocation
Day Ahead Load
Day Ahead Anc. Serv. Capacity Requirement
Hour Ahead Load
Anc. Serv. Hour Ahead Capacity Requirement
Expost Load
Actual Load

Physical Dimensions
Load Zone * Scheduling Coordinator
Load Zone
Cong Zone
System

* Supply and Demand for Capacity, Generation, and Transmission are related at the Congestion Zone Level

Data
Awarded Price-Quantity
Price Quantity Offer Curve

ECu000060661

ISO LOAD

Allocation	Awarded Price-Quantity				Price-Quantity Offer Curve			
	Load Zone & SC	Load Zone	Cong Zone	System	Load Zone & SC	Load Zone	Cong Zone	System
Day Ahead Load								
Day Ahead Anc. Serv. Capacity Requirement								
Hour Ahead Load								
Anc. Serv. Hour Ahead Capacity Requirement								
Expost Load								
Actual Load								

Possible
Released
Partially Released

ISO TRANSMISSION

Allocation
Day Ahead Flow
Hour Ahead Flow
Expost Flow
Actual Flow
Total Day Ahead Capacity
Total Hour Ahead Capacity
Total Expost Capacity
Available Day Ahead Capacity
Available Hour Ahead Capacity
Available Expost Capacity

Physical Dimensions
Congestion Zone Interface*
System

* Supply and Demand for Capacity, Generation, and Transmission are related at the Congestion Zone Level

Data
Awarded Price-Quantity
Price Quantity Offer Curve

ECu000060663

ISO TRANSMISSION

Allocation	Awarded Price-Quantity		Price-Quantity Offer Curve	
	Zone	System	Zone	System
	Interface		Interface	
Day Ahead Flow				
Hour Ahead Flow				
Expost Flow				
Actual Flow				
Total Day Ahead Capacity				
Total Hour Ahead Capacity				
Total Expost Capacity				
Available Day Ahead Capacity				
Available Hour Ahead Capacity				
Available Expost Capacity				

Possible
Released
Partially Released

Committee on Governmental Affairs
EXHIBIT #A-69

Press Release

ENRON HOSTS ANNUAL ANALYST CONFERENCE; PROVIDES BUSINESS OVERVIEW AND GOALS FOR 2000

FOR IMMEDIATE RELEASE: Thursday, January 20, 2000

HOUSTON - Enron Corp. hosted its annual equity analyst conference today in Houston. Ken Lay, Enron chairman and chief executive officer, opened the conference by highlighting Enron's tremendous growth across all businesses and the outstanding 700 percent return to shareholders over the past decade.

Enron presented key objectives for 2000:

Continued strong growth in the core Wholesale Energy businesses.

Break-out performance from Retail Energy Services.

Rapid development of Enron Broadband Services.

Enron's ability to extend core skills and competencies to new markets was a recurring theme throughout the day.

Wholesale Energy Business

Growth prospects remain strong for Wholesale Energy Operations and Services, Enron's largest business. Wholesale energy growth in North America is expected to be driven by the continuing deregulation of power markets in the United States and large-scale energy outsourcing by utilities and large energy consumers. Enron expects to continue to broaden its early lead across the European continent as markets quickly open to competition. Finally, Enron is rapidly expanding its wholesale presence in other markets such as Japan, where large customers will be permitted to choose their electricity provider in March 2000.

EnronOnline will provide additional wholesale growth as incremental sales are generated through this innovative, Internet-based transaction system. Over 450 customers around the world have used EnronOnline and over 10,000 transactions have been completed since its introduction in late November 1999. Yesterday, EnronOnline transaction levels reached a new record with over 700 transactions, representing a notional value of $250 million. Transaction processing costs with EnronOnline are significantly lower than costs associated with traditional transaction methods.

Enron's Gas Pipeline Group is also well positioned to continue growing, with expansions planned or underway on several of its systems.

Retail Energy Services

With over 16,500 facilities under management, the infrastructure is in place to service customers worldwide. As the strong contracting momentum continues, Enron Energy Services is poised to rapidly increase earnings in 2000. Enron Energy Services' goal for 2000 is to sign new

contracts representing $16 billion in future expenditures by customers for energy and energy services, nearly double the level in 1999.

Enron Broadband Services

The new name of Enron's communications business, Enron Broadband Services, reflects its role in the very fast growing market for premium broadband services. Enron is deploying an open, flexible global broadband network controlled by software intelligence, which precludes the need to invest in a traditional point-to-point fiber network. This Enron Intelligent Network is widely interconnected to both other wholesale bandwidth carriers and to Internet service providers, thus providing the platform for two new Enron business centers, bandwidth intermediation and broadband content delivery.

A direct transfer of Enron's core market making and risk management skills from its energy businesses, bandwidth intermediation will provide capacity-holders a vast array of alternatives for flexible, low cost capacity. Enron will also provide premium broadband content services, such as high-quality video-streaming and large broadband file transfer, with differentiated levels of quality in a usage-based business model.

As announced in a separate release, Enron also reached an agreement with Sun Microsystems that provides for accelerated development of broadband Internet services.

Enron is one of the world's leading electricity, natural gas and communications companies. The company, which owns approximately $34 billion in energy and communications assets, produces electricity and natural gas, develops, constructs and operates energy facilities worldwide, delivers physical commodities and financial and risk management services to customers around the world, and is developing an intelligent network platform to facilitate online business. Enron's Internet address is www.enron.com, and the stock is traded under the ticker symbol, "ENE."

##

This press release includes forward looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Although Enron believes that its expectations are based on reasonable assumptions, it can give no assurance that its goals will be achieved. Important factors that could cause actual results to differ materially from those in the forward looking statements herein include political developments in foreign countries, the ability to penetrate new wholesale and retail natural gas, electricity and broadband services markets, including the energy outsource market, in the United States and Europe, the timing and extent of changes in prices for crude oil, natural gas, electricity and those relating to broadband services and content, the timing and effect of changes in interest rates, the timing and success of Enron's efforts to develop domestic and international power, pipeline, communications, internet-related and other infrastructure projects, and conditions of the capital markets and equity markets during the periods covered by the forward looking statements.

Committee on Governmental Affairs
EXHIBIT #A-70

Press Release

ENRON ANNOUNCES INCREASED EARNINGS TARGET FOR 2001 TO $1.70 - $1.75 PER SHARE

FOR IMMEDIATE RELEASE: Thursday, January 25, 2001

HOUSTON -- Enron, at its annual investor's conference, will discuss today its confidence in increasingly strong business prospects for 2001. The company is comfortable with estimates for 2001 recurring earnings of $1.70 to $1.75 per diluted share.

The primary reasons and assumptions for the very positive outlook include:

· Enron's further strengthening of its long-standing lead in the North American wholesale energy market, significant expansion of its European wholesale energy business, and extension of Enron's business model into new, large markets;

· Significant growth prospects in Enron's retail energy business, including increases in expected total contracting from record 2000 levels of $16.1 billion to an estimated $30 billion in 2001;

· Substantial completion of Enron's low cost, flexible and scalable broadband network, expanded product offerings and an expected eight-fold increase in 2001 deliveries of bandwidth from strong 2000 levels; and

· Continued steady performance by Enron's interstate gas pipelines.

As previously announced, Enron is webcasting its annual investor conference today beginning at 8:00 a.m. CST. The meeting can be viewed at www.enron.com.

This press release includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Although Enron believes that its expectations are based on reasonable assumptions, it can give no assurance that its goals will be achieved. Important factors that could cause actual results to differ materially from those in the forward looking statements herein include success in marketing natural gas and power to wholesale customers; the ability to penetrate new retail natural gas and electricity markets, including the energy outsource market, in the United States and Europe; development of Enron's broadband network and customer demand for intermediation and content services; and conditions of the capital markets and equity markets during the periods covered by the forward looking statements.

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FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D. C. 20426

Committee on Governmental Affairs
EXHIBIT #A-71

JUN 19 2002

Mr. David Berick
Committee on Governmental Affairs
United States Senate
Washington, D.C. 20510

Dear Mr. Berick:

Per your May 30, 2002 request to Susan Court, I am enclosing a copy of a document identified by the Commission's investigation filing number 1J as a follow-up to the Commission's March 4, 2002 response to Senators Lieberman and Thompson's February 15, 2001 letter to the Commission. This document consists of a copy of staff's notes, a copy of the slide show presentation made by Mary Hain of Enron and Ellen Wolf of Tabors Carmanis, and a list of attendees at the August 24, 2000 EPSA meeting where the slide show presentation was made. We are trying to ascertain whether anyone at the Commission has a copy of the Tim Belden presentation. We will let you know later what we learn.

As noted in the Commission's March 4 response, this document is confidential and non-public. I request that you not release this document, but should the Committee decide to do so, as with the March 4 response, I request that you please give the Commission five days' notice in advance of the intended release.

If we can be of further assistance, please do not hesitate to contact me at (202) 208-0004, Cynthia Marlette at (202)208-1000, or Susan Court at (202)208-2183.

Sincerely,

Kevin F. Cadden
Director
Office of External Affairs

(15)

Meeting with California Marketers
August 24, 2000
10:00 am. Hearing Room 3

Attendees:
The meeting was conducted through EPSA, with representatives from Duke Energy, Enron, Constellation, Southern Energy, and PG&E National Energy Group. See attendance sheet for list of participants.

See slides from Enron, which provided the framework for the meeting.

The primary problem is the interaction between wholesale and retail markets.

There are major problems in the retail market:
- hedging problems
- under scheduling

But marketers aren't sure there is much that FERC can do:
- FERC is responsible for allowing ISO bid caps.
- Need publicized market information–would allow the market to self-police. More information on ISO operations is needed. Perhaps FERC could help in fostering greater market information.

The story in California is one of scarcity:
- California competes with the rest of the West for supplies.
- Load growth fueled by strong economy.
- No significant new generation in CA for last several years.
- Diminished supply of hydro this year, compared to last year. In the last few years, the western market came to rely on an abundance of hydro
- Existing generation is aging.
- Lack of available NOx credits may have prevented generators from running.

Price caps will perpetuate scarcity problem:
- CA relies on 8,000 MW of imports–plants are needed
- Power is being attracted to uncapped markets.
- Plant operating costs are increasing because gas prices are so high–gas is on the margin in WSCC
- Markets outside of CA became more valuable when CA instituted caps.
- Power plant economics will keep generators from investing in CA if price caps continue–peakers require the ability to earn back costs.
- Incentives are for generators to sell out of state.

California has tariff authority to recall exports when system reached stage 3.
Issue is not so much exports but lack of imports.

CA neighbors are struggling to meet local demands
Hydro scarcity, partly due to fish requirements

Failure of CA ISO's demand side program.

Uncertainty in marketplace will dry up growing forward markets.

Forward prices correspond to reserve market–extreme backwardation.
If new generation were anticipated to come online, forward prices would fall.

Lack of IOU hedging has distorted price impacts:
- IOUs are not using the market appropriately because they are hoping for regulatory bailout.
- ISO report details the hedging activities of IOUs.
- There are numerous hedging opportunities in bilateral markets.
- Cal PX block forward market is the only one available to IOUs.
- 80% of what utilities need to buy is being squeezed into next-day markets–like day trading retirement funds
- Hedging disincentives need to be removed from the marketplace
- IOUs do have some ability to hedge, but they are not using it–instead relying in regulatory bail-out. Some IOUs didn't even hedge volumes approved by CPUC.

Bilateral markets are working well. The Palo Verde and COB hubs in bilateral market are liquid. Not much is traded through NYMEX, most forwards are OTC.

Forward trades to 2006 and beyond are made frequently.

Generators have made every effort to meet load. Producing much higher percentage of power than ever before.

Shortage of hydro
Running out of NOx credits–ability to generate constrained because of emissions restrictions

Under scheduling by IOUs:
- Under scheduling in hopes of keeping prices low–gaming behavior. IOUs are under representing expected loads (demand) to lower prices.
- IOUs exercising monopsony power–only they know their loads
- ISO gets load forecasts from IOUs, but also does its own load forecast.
- Over time, this behavior has shifted supply out of day-ahead markets.

What can FERC do?
- FERC has the opportunity to look behind the charts and graphs. Some of them don't make sense. Tension between making information available and need for confidentiality.
- FERC should look at buying patterns of IOUs. Need to think about business line IOUs see themselves in. If they want to be a wires company, they wouldn't want to sign long-term bilateral deals.

- A lot of these issues are state political issues.
- Enron doesn't want to see FERC do something on the wholesale side to screw things up.

Problems with western markets:
- low hydro
- higher loads (driven by booming economy)
- high gas prices
- no price signals from retail market

How do marketers interact with the market?
- For PG&E, half of trading is asset based, half financially based
- work with marketers to provide service to customers
- price and offer tailored products
- try to position themselves to take advantage of discrepancies in the market
- Marketers are not looking at marginal cost per se, but looking at opportunity costs of operating in those markets. Price is based on opportunities in other markets (both regionally and other fuels, e.g., spark spreads)

Mandatory must buy from PX?
- allowing bilateral deals for IOUs is not a panacea.
- IOUs are unable to manage risk using only block forwards

Assessment of CA market monitors?
- They are captured –tied to various organizations
- There isn't the rigor in analysis that one would expect
- The 9% figure for market concentration of generators doesn't take into account that many generators are must-run units in market.
- ISO staff is in tough situation–mixed direction from political forces
- Market Surveillance Committee is somewhat better

(J) 8/22/2000

What About the California Wholesale Market Really Needs Fixing?

August 24, 2000

Summary

- High prices in peak periods are the result of scarcity and are necessary to incent needed generation investment
- California Retail/Wholesale Market Interaction
  - Retail customers are benefiting from the low prices during shoulder months caused by wholesale competition
  - The major problem is in the retail market where high peak period wholesale prices have not been mitigated by forward purchases
  - Underscheduling in forward market causes high demand and reliability problems during peak time

Summary (Continued)

- Some wholesale market remedies are necessary now
  - The FERC should analyze whether there are Market Power Concerns Associated with Times of Scarcity and then determine appropriate level of Price Caps
  - Publicize Market Information
  - Encourage structural technological innovation to enhance demand side participation

Agenda

- Supply and demand data showing scarcity
- Current supply/demand economics
- Background - ISO and PX market structure
- Regulatory overlay
- Explanation of retail market problems
- Wholesale market issues requiring staff investigation
- Recommendations

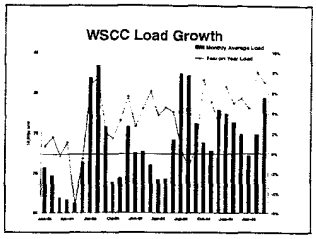
Western Supply and Demand Fundamentals

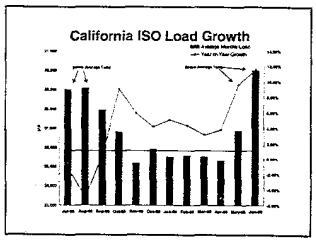
Western Supply and Demand Indicates Scarcity

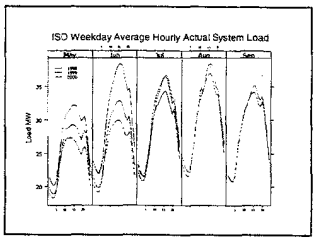
- California competes vigorously with the rest of the growing west for increasingly scarce supplies
- Load growth fueled by strong economy
- No significant new generation in California since the 1980s
- Market was fooled by excellent hydro years
- The existing thermal generation fleet is aging: 81% > 30 years
- The complete lack of available NOx credits may have prevented generators from running

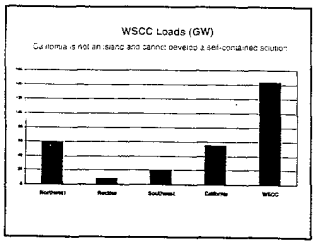
California Competes with the Rest of the West for Scarce Supplies

- Ample long distance transmission
- Traditional Northwest players best opportunities often outside of the NW
  - Powerex Accesses Alberta Pool, Northwest, California
  - BPA often prices below other at PX index once
  - Spread between COB and Northern California close to $0 MWH
- Turbine market is national => Northwest and California must compete with all of North America for new resources









WSCC Capacity Additions

	Summer 2000	Summer 2001	Summer 2002
Northwest	7	780	851
California	-0-	1000	2648
Southwest / Rockies	908	2390	692
Total	915	4150	4181
Estimated Load Growth (Assumes 3% Escalation)	(3600)	(3708)	(3819)

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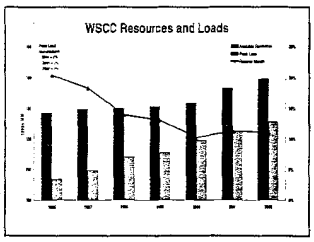
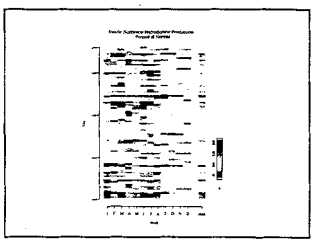
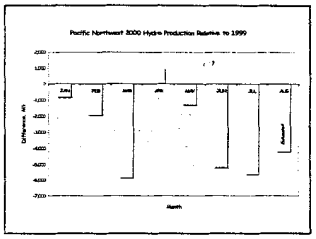


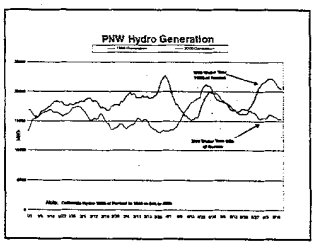
Has Recent Unusually Strong Hydro Fooled Us?

Volume Runoff Percent of Normal

	Columbia River	California
2000	93%	94%
1999	116%	108%
1998	96%	153%
1997	152%	84%
1996	138%	129%







In Sum, Scarcity is Real - Generation is Needed

- Scarcity is real
- Energy prices driven by scarcity
- New generation required

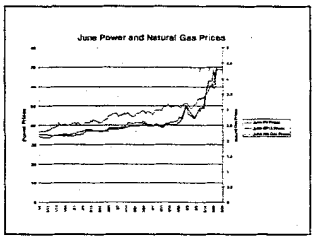
Current Supply/Demand Economics

FERC Regulatory Overlay

- Allowed Cal. ISO to set "old" caps
  - Price reduced from $250 to $750 on 10/1/99
  - Reduced from $750 to $500 on 6/29/00
  - Reduced from $500 to $250 on 8/7/00
- Cal PX - recently reduced from $2500 implicit cap to $350 explicit cap

Price Controls Will Perpetuate Scarcity

- Power plants are needed! Demand is still not very price responsive
- Operating costs of plants are increasing
  - Gas prices high
  - Gas generally is on the Margin in WSCC (i.e., Gas-fired generation sets the electricity generating market price)
- Power plant economics will keep generators from investing in generation if they anticipate price cap
- In state and out of state generation will be incented to sell out of state



Power Plant Economics

- Investors will not invest in power plants if they can only earn short term marginal cost (i.e., the cost of fuel and operation and maintenance without earning a return on their investments)
- The $250 price cap may not provide a return on investment

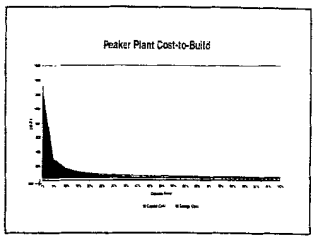
Peaker Plant Economics

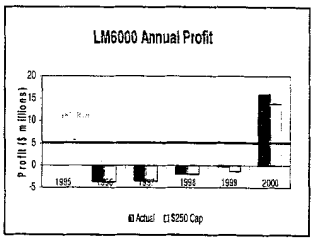
Technology:	GE LM 6000
Fuel:	Natural Gas
Heat Rate:	10,000 Btu/Kwh
Capacity:	48 MW
Capital Structure:	
60% Debt @ 9%	
40% Equity @ 18%	
15 Year Amortization	
Total Cost to Build:	$27 million
Annual Capital Recovery:	$3.7 million
Annual Fixed O&M:	$1.5 million
Annual Total:	$5.2 million

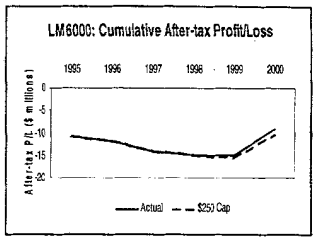
8/22/2000

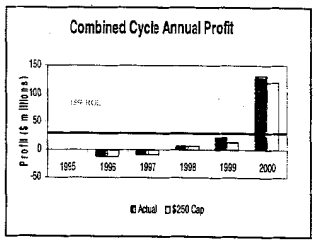
Baseload Plant Economics

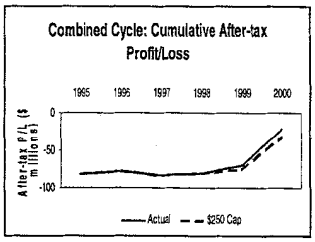
- Technology: GE Frame 7FA Combined Cycle
- Fuel: Natural Gas
- Heat Rate: 7,100 Btu/Kwh
- Capacity: 250 MW
- Capital Structure
  - 50% Debt @ 9%
  - 50% Equity @ 15%
  - 15 Year Amortization
- Total Cost to Build: $180 million
- Annual Capital Recovery: 24 million
- Annual Fixed O&M: 3 million
- Annual Total: $27 million











Load Responsiveness

- 2700 MW of Load theoretically available under the Interruptible Tariffs
- New Load Management Programs Have Been Expensive and Small
  - 100 MW to 300 MW of Shared Savings with Quite When Prices Exceed $250/MWh
  - 230 MW in DA ISO Participating Load Agreement with Capacity Costs of $750/MWh and Energy Costs Up to $750/MWh
  - Seldom Used - Most Participants Already Under Interruptible Tariff

The ISO's Demand Side Program Has Not Been Very Effective

- The proponents of price caps claim that as soon as the demand side is "workably competitive" then there is no need for price caps
- But if ISO sets the caps too low it will not get demand response
- The utilities have up to 2700 MW of available interruptible load, yet only a small fraction responds when called (600 MW)
- Uncut loads willingly lose value of up to $1,500 per MWh
- Thus, during times of scarcity, the value of energy is at least $1,500 per MWh

Price Controls are Detrimental to Investment and Other Markets

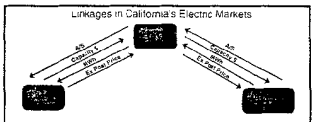
- Merchant generation subject to volatile commodity prices – caps will inhibit investment
- Creates asymmetry between load response and generation
- Suppliers will sell outside California where markets are more predictable and prices are higher
- Because of the interdependent linkages in California's electric market, cannot change one aspect of structure without impacting all others
- Uncertainty in the marketplace will dry up the growing forward markets

Background
ISO and PX Market

California Independent System Operator

- Real Time Energy Market - Based on complex computer model
- Day ahead and hour ahead ancillary service market
- Day ahead and hour ahead transmission market

Linkages in California's Electric Markets



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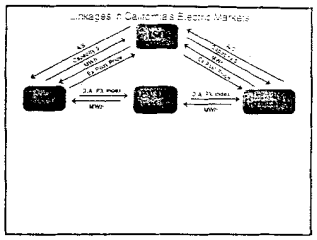
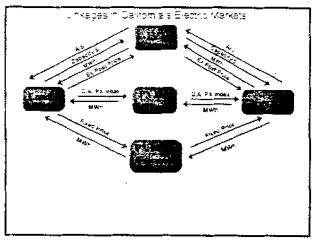
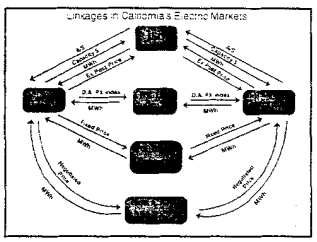
California Power Exchange

- Day Ahead Energy Market - Simple price auction based on prices of supply and demand bids.
- IOUs all energy purchased from this market deemed prudent by PUC







California Regulatory Overlay

- Assembly Bill 1890
  - Provided mechanism for recovery of stranded costs.
  - Required divestiture of thermal generating resources.
  - Froze IOU retail rates until either April of 2002 or stranded costs are recovered, whichever is sooner.

Recent California Events

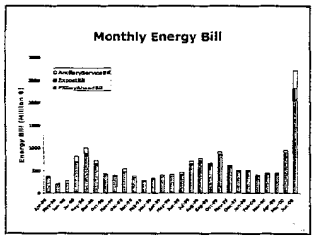
- CPUC limits on hedging in the "forward" (longer term) market
- 8/03/00 CPUC allowed PG&E and SoCal Edison to do bilateral deals in forward market (subject to previously established hedging limits) if PX schedules the deal.
- CPUC performs expedited, upfront prudence review
- CPUC considering similar proposal by SDG&E

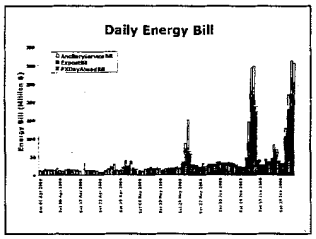
8/22/2000

Retail/Wholesale
Market Interaction

Are Retail Prices High and Do They Indicate Wholesale Market Failures?

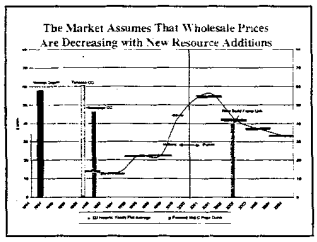
- DMA admits that there is authentic competition for 98-99% of the total annual hours
- It assumes that market power is present when bids exceed only short run marginal costs rather than considering long term returns or other market power indices.

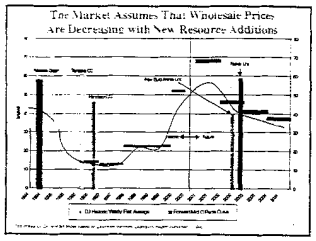




Do these Prices Warrant Wholesale Market Intervention?

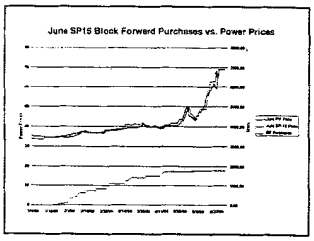
- Overall, even with scarcity conditions, retail prices have not been significantly increased due to wholesale competition in California (for SDG&E 10-20 percent annual increase, possible 10-20% overall decrease when adjusted for SDG&E rebate)
- Is it appropriate to institute wholesale price controls to mitigate retail price risk?
- Wholesale futures prices are behaving rationally regardless of these short term retail prices





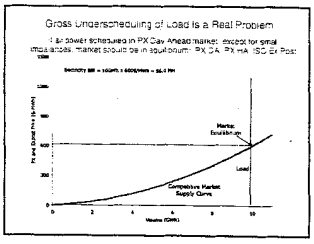
Lack of IOU Hedging Has Distorted Price Impacts

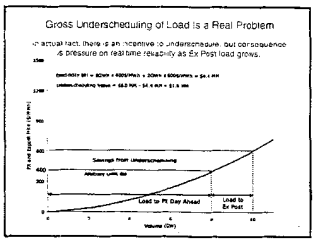
- The IOUs had a choice of buying the power in the PX Block Forward, PX Day Ahead, PX Day Of and CAISO Ex Post.
- Hedging limits prevented some purchases of forward energy.
- IOU claims notwithstanding, there have been significant opportunities to hedge forward prices
  - ~ 1800 MW in entire PX block forward for SP15 in June, 2000
  - Only ~800 MW for SCE out of 2,200 MW authorized
  - Clear market signals to hedge
- Fear of prudence review kept IOUs from hedging the risk of day ahead and real time prices

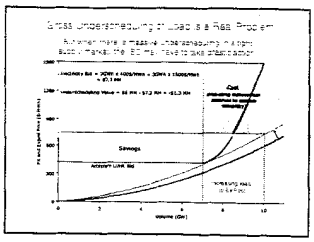


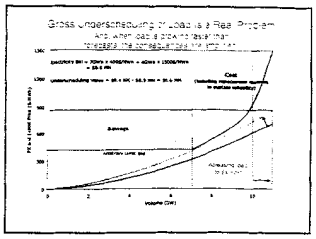
Stranded Cost Recovery Incents IOUs to Underschedule in the Forward Market and Buy in the Spot Market

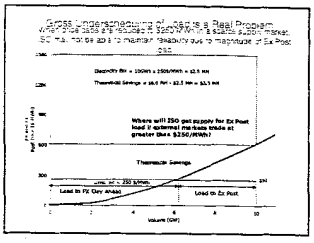
- CTC payments can theoretically be increased by underscheduling demand in the PX Day ahead markets
- But, underscheduling demand increases ISO prices and reduces reliability
  - ~ 30% of ISO load in real time market on 06.14/00
  - Only 100 MW of blackouts--a remarkable achievement











Underscheduling's Effects on Reliability Are Observable

- Stage 1 Emergency
  - In Anticipation of Low Reserves
  - Users Asked to Voluntarily Reduce Consumption
  - 15 Times From May 22 to August 5
- Stage 2 Emergency
  - Reserves Fall Below 5%
  - 2700 MW of Interruptible Load Curtailed
  - 9 Times From May 22 to August 5
- Stage 3 Emergency
  - Reserves Fall Below 1.5%
  - Firm Load Cut - Rolling Blackouts
  - 0 Times From May 22 to August 5

Wholesale Market: Remedies Necessary Now

- Analyze whether there are market power concerns associated with times of scarcity and then determine appropriate level of price caps
- Publicize market information
- Encourage structural/technological innovation to enhance demand side participation
- Don't mistake San Diego's failure to hedge as failures in the wholesale market
- Decide whether FERC has a role in the underscheduling issue: Are the California utilities exercising monopsony power by underscheduling load into the PX day ahead market?

ISO Should Do More Rigorous Market Power Analysis

- The Market Analysis Unit report and the UC Energy Institute Report wrongly uses pricing above short term marginal cost to conclude that there is market power
- Some market power analysis failed to take into consideration changes in supply and demand like the decrease in hydro generation
- To distinguish market power from scarcity, FERC should instruct the ISO to use rigorous analytical measures to determine market power
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ISO Should Allow Scarcity Rents

- At points of scarcity (e.g., at Stage 2 when you're getting low on reserves and you're cutting load) marginal cost is no longer a reasonable price.
- Rather when you reach scarcity you should price scarcity rents at the value of energy (e.g., $1,500 as illustrated in the interruptible market

To Investigate the Source of High Prices FERC Should Review:

- High gas prices
- Below normal hydro
- Lack of NOx credits
- High demand
- How many MWs did the CAISO procure during the Summer 2000 compared with 1999?
- Has PG&E changed its bidding behavior associated with its Hydro facilities in 2000?
- Were baseload facilities operated differently in 2000 than in 1999?

To Investigate the Source of High Prices FERC Should Review (Continued)

- Were any generation plants off-line due to unplanned maintenance during Summer 2000?
- Were other Western power markets prices higher (year-on-year)?
- What options did SDG&E have to "hedge" its retail rates?
- What were prices in the CAL PX block forward market on Jan 15, 2000 and May 15, 2000?
- FERC and the ISO should consider the regional impacts of any price caps implemented in California, such as prices not corresponding to flows

Other Market Growing Pains

- Only a limited number of out-of state participants can access spin and non-spin markets
- Rate freeze prevents consumers from receiving price signals (i.e., some amount of load increase is illogical behavior)
- Intrazonal congestion not explicitly priced--Socialized across all loads
- Complex computer model used to price transmission
- Relatively little transmission available in forward markets
- Stakeholder board subject to political pressure
- Forward market liquidity has evaporated due to price cap changes

We Do Not Have All the Answers. Why?

- Much information that is necessary to analyze the California PX and ISO markets is not available to markets participants
- We believe that California can significantly enhance competition in its electricity markets if this information is made available

Why Would Information Make the Market More Competitive?

- Publishing price information would provide better price signals producing a more efficient market
- Publishing generation and load information would remove competitive advantages held by monopsony load servers and generators with a large percentage of the market
- Publishing transmission information would remove the ATC knowledge advantage retained by grandfathered transmission contract holders
- More information would help the market to self-police

Generation and Load Information That Should be Available

- After the fact actual meter information depicting actual unit-by-unit production and consumption within each zone.
- Unit outage information showing planned and forced outages.
- Water levels, or hydro outputs. Weekly/monthly information.
- Data on significant unit outages etc. in the peak prices hours in question.
- Calls by the ISO on plants with Reliability Must Run contracts.

Energy and Ancillary Service Price Information That Should be Available

- All bid information in both Day Ahead and Hour Ahead Markets, including generation and load energy and ancillary services
- The information for these markets should include initial preferred schedules, final schedules and the BEEP stack, all day ahead load and generation bids by Scheduling Coordinator

Transmission Information That Should be Available

- The information should include adjustment bids, day ahead schedules, hour ahead schedules, real time adjustments, actual flows, and transmission availability by category of ownership
- This information should be provided for all transmission lines
- Significant intra-zonal congestion by transmission path
- Data should be differentiated by existing and new, firm use transmission contracts

When Should This Information Be Available?

- The information listed above ought to be provided as close to "real time" as possible.
- At a minimum it ought to be provided to the market within 24 hours.

8/24/99

NAME	COMPANY	PHONE	E-MAIL
Gerald Williams	FERC	202.219.2584	gerald.williams@ferc.fed.
Michelle Veloso	FERC	202/208-2008	michelle.veloso@ferc.fed
Julie Simon	Electric Power Supply Association	202-789-7200	jsimon@epsa.org
Scott Krantz	Duke Energy	801-531-5467	spkrantz@duke-energy.com
John Rubin	FERC	202-208-0808	
Lee Barrett	Duke Energy	713/627-6579	lebarrett@duke-energy..
Gwen Hemingway	FERC OMTK	202/208-2923	Gwen.Hemingway@ferc.fed.
Ellen Wolfe	TCA for Enron	916/791-4533	ellen@tca-us.com
Diane Featherstone	Constellation	410 468 3700	diane.featherstone@powersrc..
Mike McLenahan	Southern Energy	(678)579-3288	mike.mclenahan@southernenergy.com
John Morris	PG&E-NEG	301-280-6054	jo... morris@gen.pge.c..
George Radan	PG&E NEG	301 280-6030	george.radan@neg.pge..
Jack Hawks	PG&E NEG	301-280-6805	jack.hawks@neg.pge.com
Joe Hartsoe	Enron	202 466 9150	jhartsoe@enron.com
MARK BENNETT	EPSA	202-789-7200	mbennett@epsa.org
Peter Kadzik	EPSA/Dickstein, et al	202-775-4704	KADZIKP@dsmo.com
JOHN KROEGER	FERC MARKET OVERSIGHT + ENFORCEMENT	202-208-1232	John.Kroeger@ferc.fed..
Camilla Ng	FERC Energy Markets	202-208-0706	camilla.ng@FERC.fed..
Kumar Agarwal	Energy Mkts	202.219.1066	pradeep.agarwal@ferc.fed
Robert Fallon	Dickstein, Shapiro, Morin & Oshinsky	(202)861-9134	fallonr@DSMO.com
Scott Miller	FERC	(202) 208-2171	scott.miller.ferc.fed.us
Andrea Wolfman	FERC	202-208-2097	andrea.wolfman@ferc.fed.us
Mary Hain	Enron	503-464-8862	mary.hain@enron.com

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Committee on Governmental Affairs
EXHIBIT #A-72

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What To Do About Western Wholesale Markets?

August 25, 2000

Tim Belden
Enron North America
West Power

ENRON

EC4-000662137

Summary

- High prices in peak periods are the result of scarcity and are necessary to incent needed generation investment
- California Retail/Wholesale Market Interaction
  - Retail customers are benefiting from the low prices during shoulder months caused by wholesale competition
  - The major problem is in the retail market where high peak period wholesale prices have not been mitigated by forward purchases
  - Underscheduling in forward market causes high demand and reliability problems during real time

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Summary (Continued)

- Some wholesale market remedies are necessary now
  - The FERC should analyze whether there are Market Power Concerns Associated with Times of Scarcity and then determine appropriate level of Price Caps
  - Publicize Market Information
  - Encourage structure/ technological innovation to enhance demand side participation

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Agenda

- Market Fundamentals Indicate Scarcity Exists
- Supply Side and Demand Side Economics
- Retail Design Issues
- Wholesale Market Remedies

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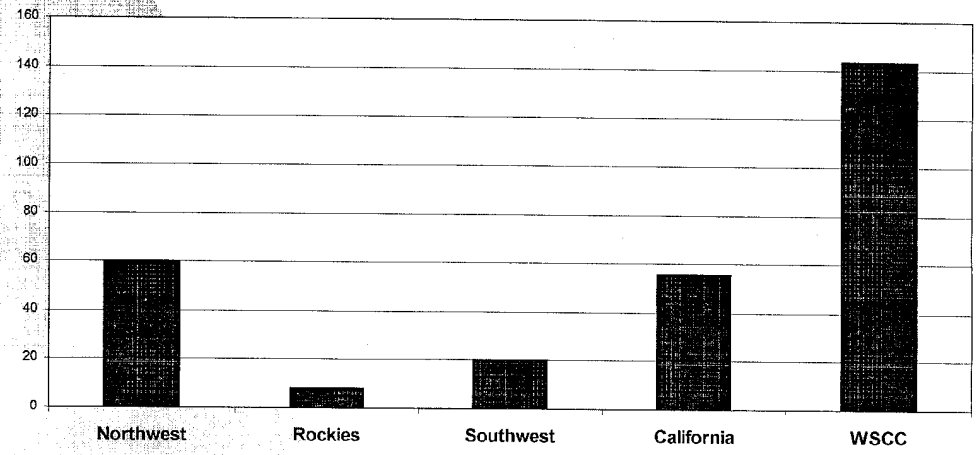
Western Supply and Demand Fundamentals

WSCC Loads (GW)

California is not an island and cannot develop a self-contained solution.



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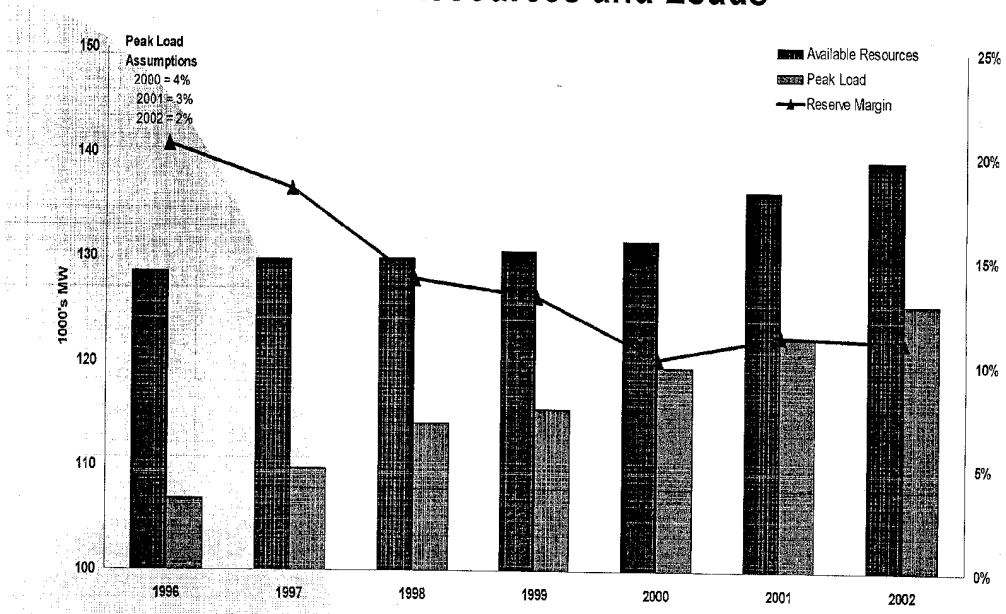
WSCC Resources and Loads



Base data from WSCC. Adjustments made by Enron based on verifiable data inaccuracies.

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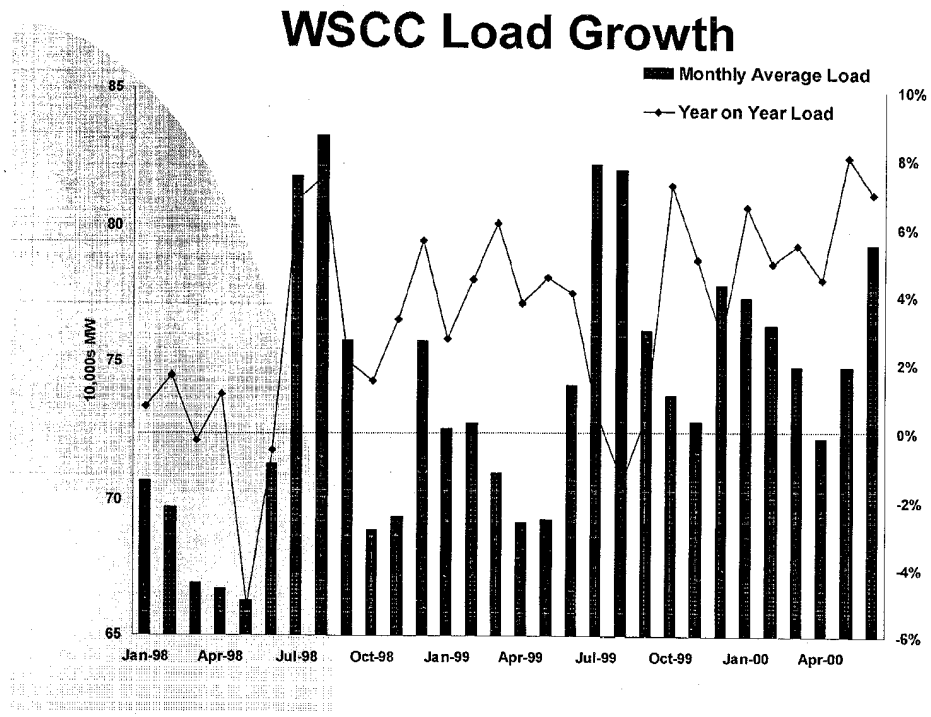

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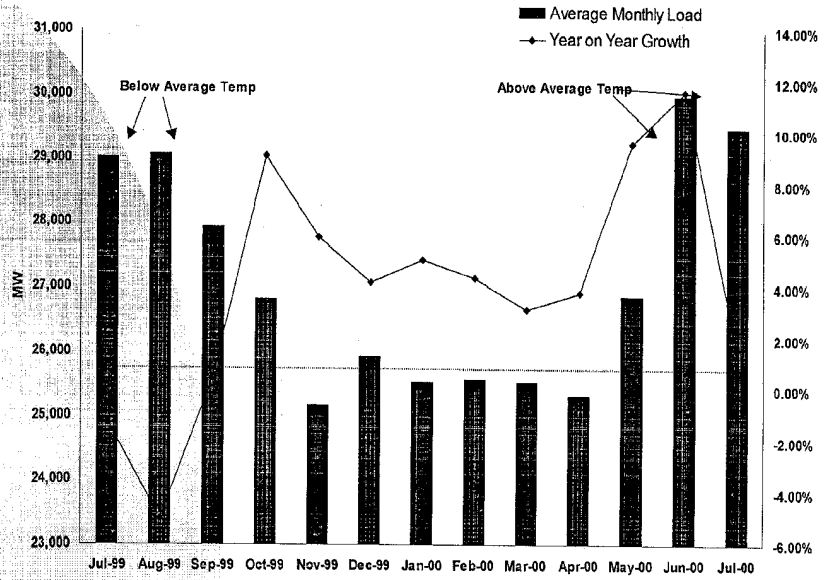
California ISO Load Growth

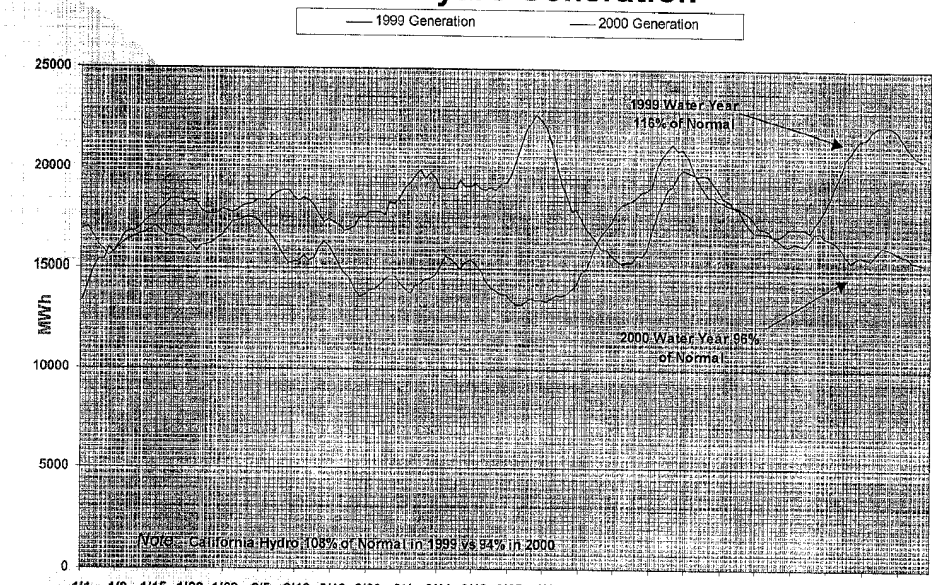


Has Recent Unusually Strong Hydro Fooled Us?

Volume Runoff Percent of Normal

	Columbia River	California
2000	93%	94%
1999	116%	108%
1998	98%	153%
1997	152%	84%
1996	138%	129%

PNW Hydro Generation



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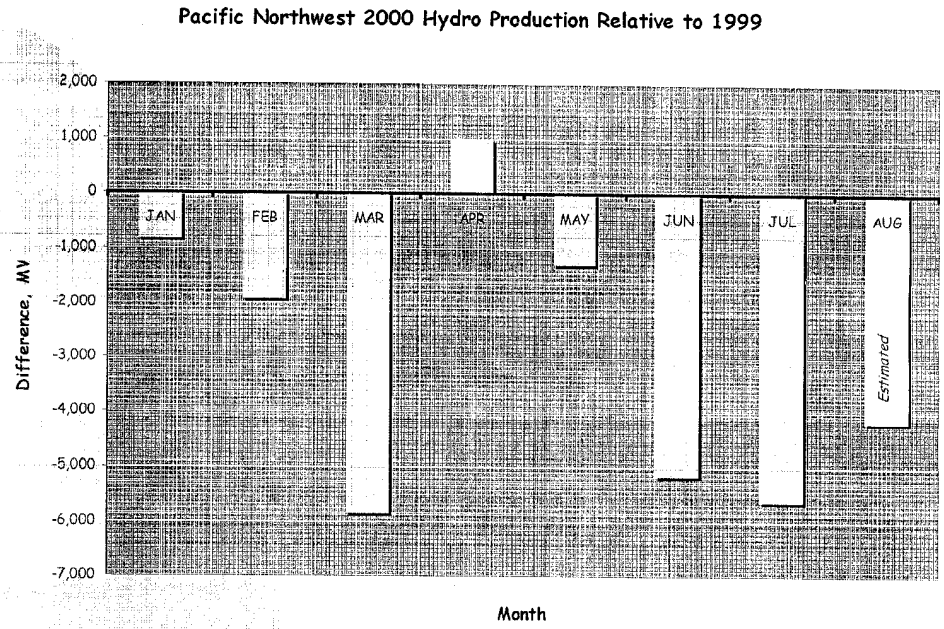

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WSCC Capacity Additions

	Summer 2000	Summer 2001	Summer 2002
Northwest	7	760	851
California	-0-	1000	2648
Southwest / Rockies	908	2390	692
Total	915	4150	4191
Estimated Load Growth (Assumes 3% Escalation)	(3600)	(3708)	(3819)

In Sum, Scarcity is Real - Generation is Needed

- Scarcity is real
- Energy prices driven by scarcity
- New generation or demand-side resources are required

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Current Supply/Demand Economics

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Power Economics

- Power is a Bust and Boom Commodity -- Merchant Generators Lose Money in Some Years and Make it Up During Times of Scarcity
- California Demand Side Resources are Far More Expensive than Supply Side Resources
- Demand Side and Supply Side Resources Should Receive Symmetrical Treatment with Respect to Price Signals

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Peaker Plant Economics

- Technology: GE LM 6000
- Fuel: Natural Gas
- Heat Rate: 10,000 Btu/Kwh
- Capacity: 48 MW
- Capital Structure:
  - 60% Debt @ 9%
  - 40% Equity @ 18%
  - 15 Year Amortization
- Total Cost to Build: $27 million
- Annual Capital Recovery: $3.7 million
- Annual Fixed O&M: $1.5 million
- Annual Total: $5.2 million

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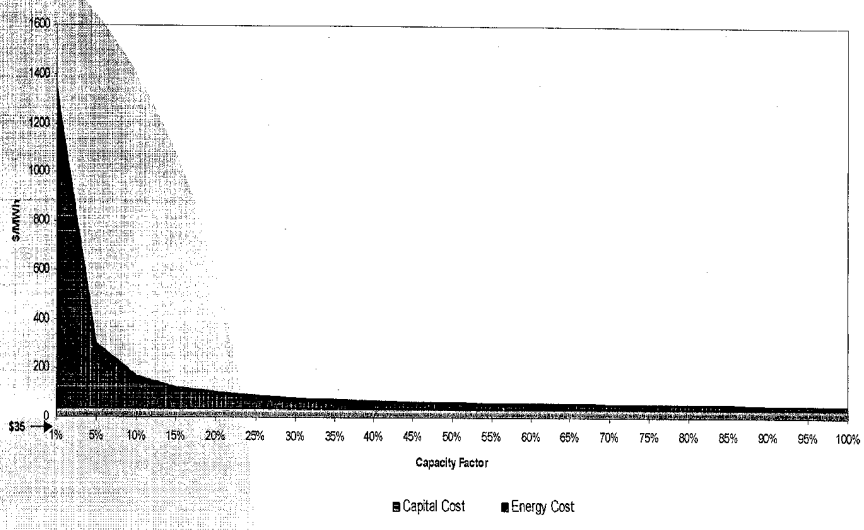
Peaker Plant Cost-to-Build



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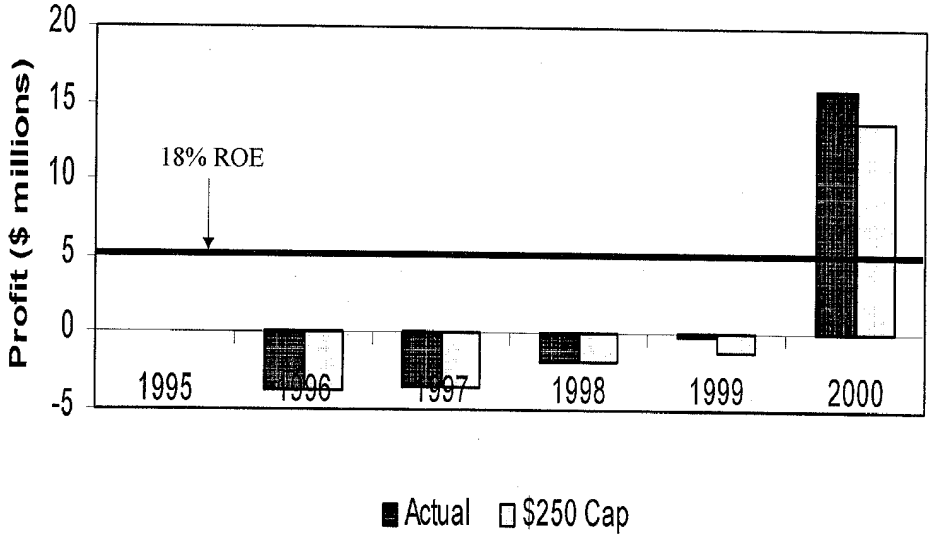
LM6000 Annual Profit



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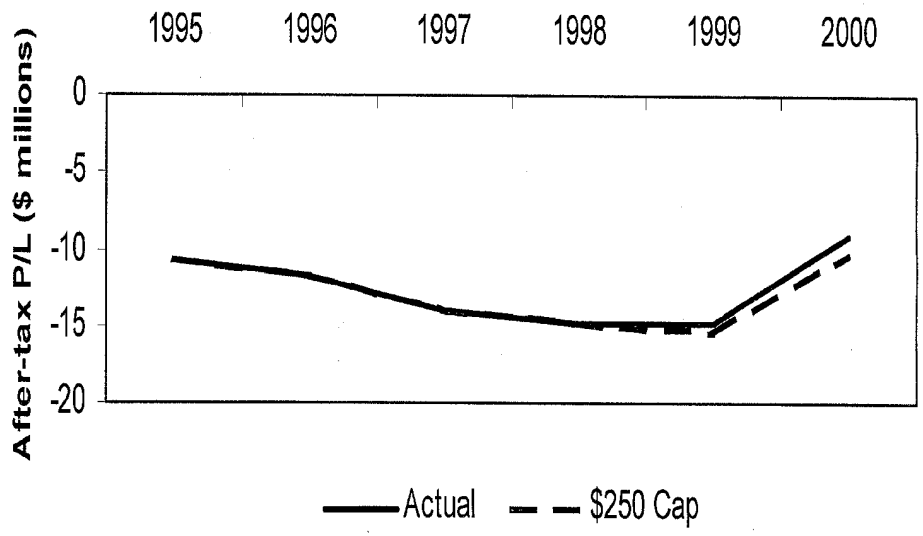
LM6000: Cumulative After-tax Profit/Loss



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Baseload Plant Economics

▪ Technology: Combined Cycle	GE Frame 7FA
▪ Fuel:	Natural Gas
▪ Heat Rate:	7,100 Btu/Kwh
▪ Capacity:	280 MW
▪ Capital Structure:	
◆ 50% Debt @ 9%	
◆ 50% Equity @ 15%	
◆ 15 Year Amortization	
▪ Total Cost to Build:	$180 million
▪ Annual Capital Recovery:	24 million
▪ Annual Fixed O&M:	3 million
▪ Annual Total:	$27 million

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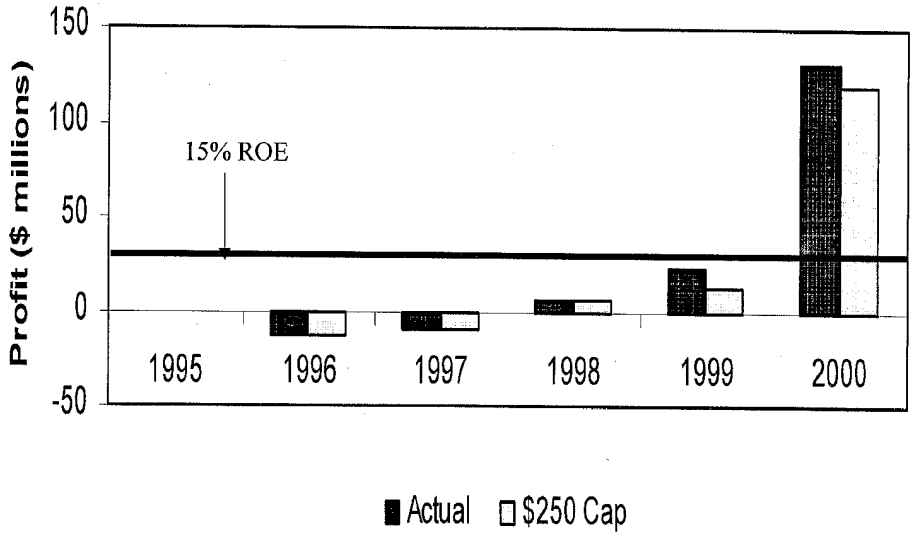
Combined Cycle Annual Profit



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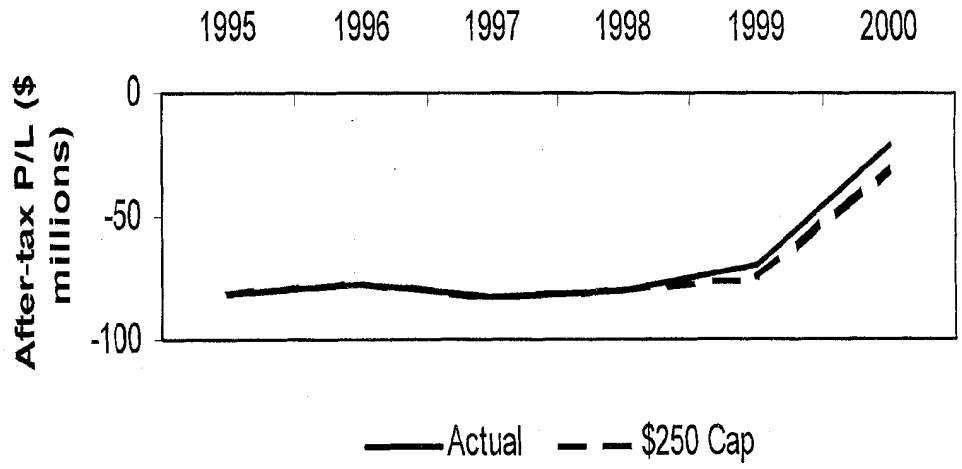
Combined Cycle: Cumulative After-tax Profit/Loss



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Load Responsiveness

- 2700 MW of Load theoretically available under the Interruptible Tariffs
- New Load Management Programs Have Been Expensive and Small
  - 100 MW to 300 MW of Shared Savings with IOU's When Prices Exceed $250/MWh
  - 230 MW in CAISO Participating Load Agreement with Capacity Costs of $750/MWh and Energy Costs Up to $750/MWh
  - Seldom Used - Most Participants Already Under Interruptible Tariff

Source: ISO DMA August 10 Report

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The ISO's Demand Side Program Has Not Been Very Effective

- The proponents of price caps claim that as soon as the demand side is "workably competitive" then there is no need for price caps
- But if ISO sets the caps too low it will not get demand response
- The utilities have up to 2700 MW of available interruptible load, yet only a small fraction responds when called (600 MW)
- Uncut loads willingly lose value of up to $1,500 per MWh
- Thus, during times of scarcity, the value of energy is at least $1,500 per MWh

Price Controls Will Perpetuate Scarcity

- Power plants are needed; Demand is still not very price responsive
- Operating costs of plants are increasing
  - Gas prices high
  - Gas generally is on the Margin in WSCC (I.e., Gas-fired generation sets the electricity generating market price)
- Power plant economics will keep generators from investing in generation if they anticipate price cap
- In state and out of state generation will be incented to sell out of state

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Price Controls are Detrimental to Investment and Other Markets

- Merchant generation subject to volatile commodity prices -- caps will inhibit investment
- Creates asymmetry between load response and generation
- Suppliers will sell outside California where markets are more predictable and prices are higher.
- Because of the interdependent linkages in California's electric market, cannot change one aspect of structure without impacting all others
- Uncertainty in the marketplace will dry up the growing forward markets

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Retail Market Design Issues

Retail Issues

- SCE and PG&E Customers Receive No Price Signals Due to CTC Balancing Accounts.
- SDG&E Customers Entered Volatile Short Term Commodity Markets Without Knowing About Risk and Without SDG&E Hedging For Them.
- Limits on IOU Forward Hedging Forces Large Volumes Into Day Ahead and Real Time Markets Which Contributes to Volatility.
- CTC Recovery Mechanism Incents IOU's to Take Large Volumes to Real Time Market.

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Lack of IOU Hedging Has Distorted Price Impacts

- The IOUs had a choice of buying their power in the PX Block Forward, PX Day Ahead, PX Day Of, and CAISO Ex Post
- Hedging limits prevented some purchases of forward energy
- IOU claims notwithstanding, there *have* been significant opportunities to hedge forward prices
  - ~ 1800 MW in entire PX block forward for SP15 in June, 2000
  - Only ~800 MW for SCE out of 2,200 MW authorized
  - Clear market signals to hedge
- Fear of prudence review kept IOUs from hedging the risk of day ahead and real time prices

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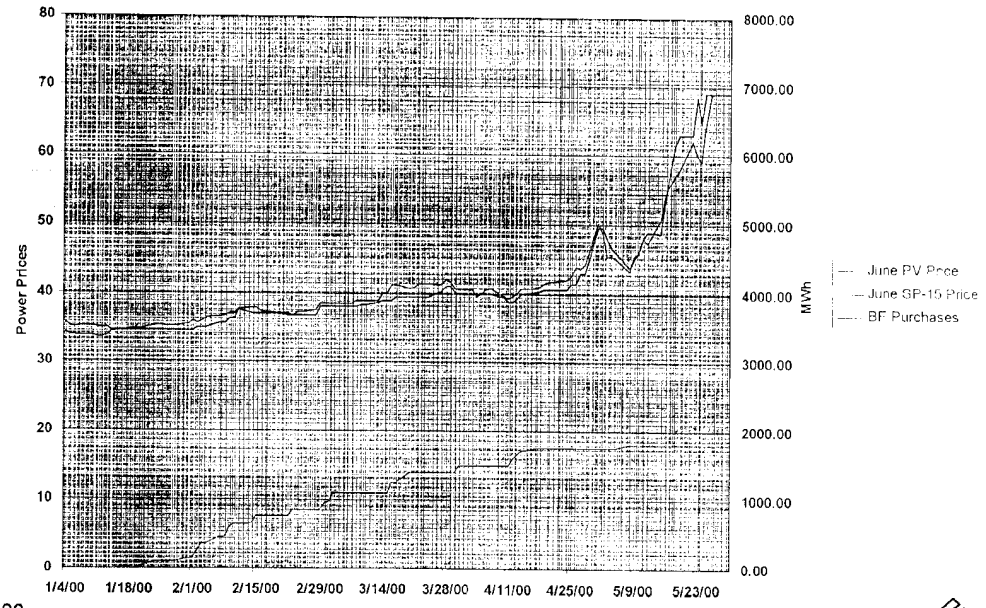
June SP15 Block Forward Purchases vs. Power Prices



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Stranded Cost Recovery Incents IOUs to Underschedule in the Forward Market and Buy in the Spot Market

- CTC payments can theoretically be increased by underscheduling demand in the PX Day ahead markets
- But, underscheduling demand increases ISO prices and reduces reliability
  - ~ 30% of ISO load in real time market on 06/14/00
  - Only 100 MW of blackouts--a remarkable achievement

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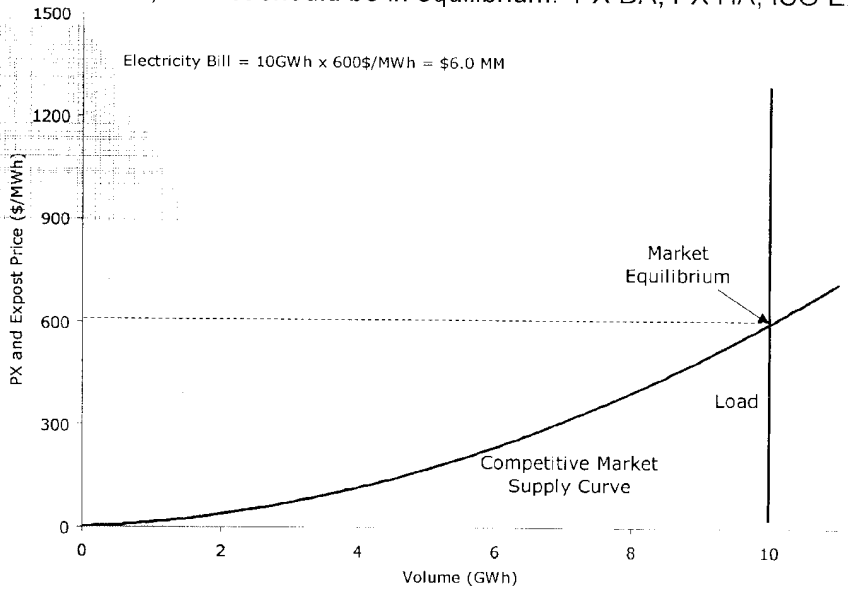
Gross Underscheduling of Load Is a Real Problem

If all power scheduled in PX Day Ahead market, except for small imbalances, market should be in equilibrium: PX DA, PX HA, ISO Ex Post



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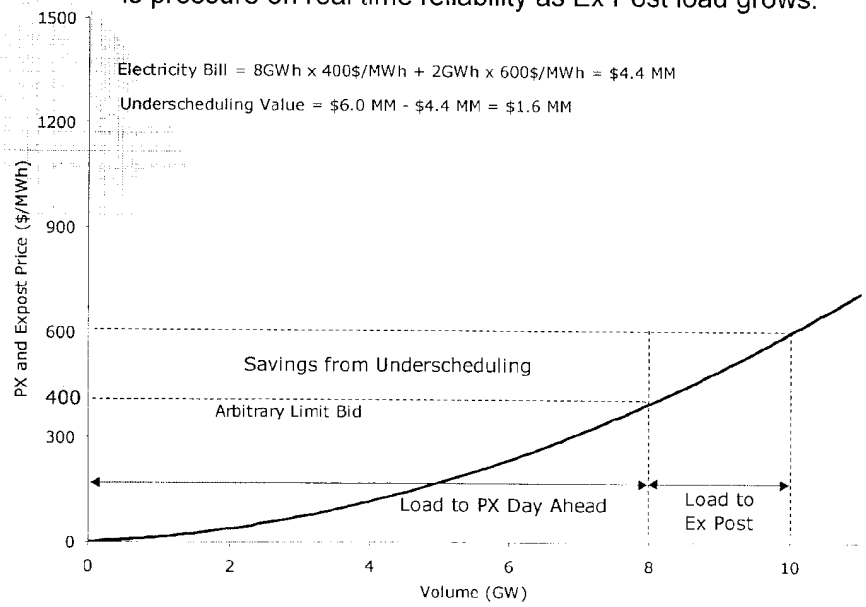
Gross Underscheduling of Load Is a Real Problem

In actual fact, there is an incentive to underschedule, but consequence is pressure on real time reliability as Ex Post load grows.



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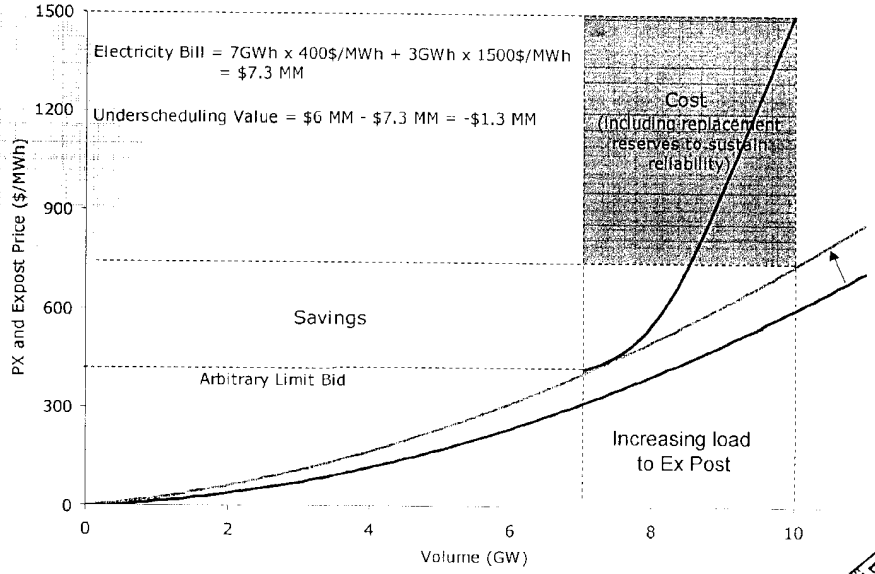
Gross Underscheduling of Load Is a Real Problem

But when there is massive underscheduling in a tight supply market, the ISO may have to take drastic action.



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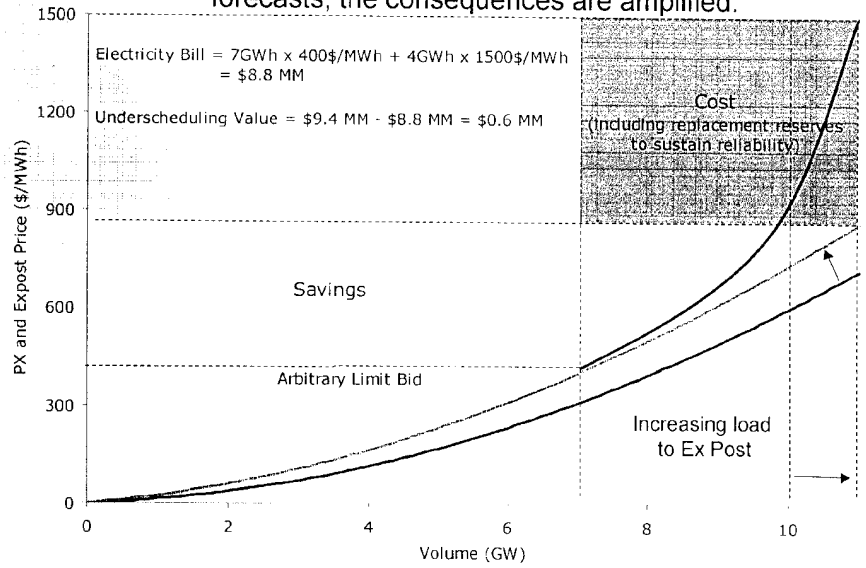
Gross Underscheduling of Load Is a Real Problem

And, when load is growing faster than forecasts, the consequences are amplified.



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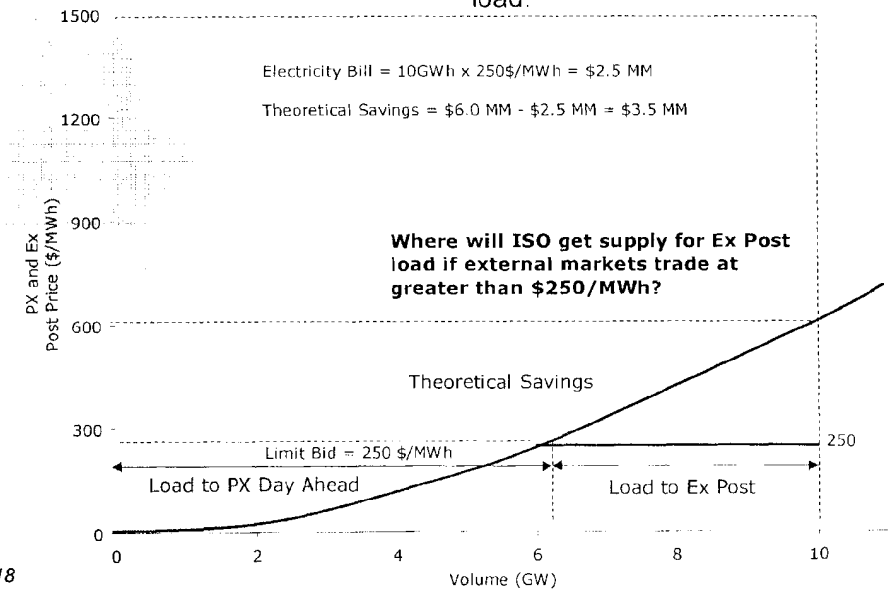
Gross Underscheduling of Load Is a Real Problem

When price caps are reduced to $250/MWh in a scarce supply market, ISO may not be able to maintain reliability due to magnitude of Ex Post load.



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Underscheduling's Effects on Reliability Are Observable

- Stage 1 Emergency
  - In Anticipation of Low Reserves
  - Users Asked to Voluntarily Reduce Consumption
  - 15 Times From May 22 to August 5
- Stage 2 Emergency
  - Reserves Fall Below 5%
  - 2700 MW of Interruptible Load Curtailed
  - 9 Times From May 22 to August 5
- Stage 3 Emergency
  - Reserves Fall Below 1.5%
  - Firm Load Cut - Rolling Blackouts
  - 0 Times From May 22 to August 5

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ECd-00062174

Retail Design Flaws Are Largest Contributor to Problem

- California should fix its retail problems first.
- Should remove barriers to hedging.
- Should systematically examine relationship between retail and wholesale market design.
- Knee-jerk reactions in wholesale markets will not solve the problem.

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ECd.000662175

Wholesale Market Issues

- Analyze whether there are market power concerns associated with times of scarcity and then determine appropriate level of price caps
- Publicize market information
- Encourage structure/ technological innovation to enhance demand side participation
- Don't mistake San Diego's failure to hedge as failures in the wholesale market
- Decide whether FERC has a role in the underscheduling issue: Are the California utilities exercising monopsony power by underscheduling load into the PX day ahead market?

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ISO Should Do More Rigorous Market Power Analysis

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- To distinguish market power from scarcity, FERC should instruct the ISO to use rigorous analytical measures to determine market power
- Under such measures Enron does not have market power

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Market Power or Scarcity Rents?

- At points of scarcity (e.g., at Stage 2 when you're getting low on reserves and you're cutting load) marginal cost is no longer a reasonable price.
- Rather when you reach scarcity you should price scarcity rents at the value of energy (e.g., $1,500 as illustrated in the interruptible market)

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To Investigate the Source of High Prices FERC Should Review:

- High gas prices
- Below normal Hydro
- Lack of NOx credits
- Planned Outages and Forced Outages in June
- High demand
- Real Capacity Margins in Western Markets
- Relationship between Wholesale Market Design and Retail Market Design
- Relationship between California Market and Other Western Markets

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To Investigate the Source of High Prices FERC Should Review (Continued)

- Were any generation plants off-line due to unplanned maintenance during Summer 2000?
- Were other Western power markets prices higher (year-on-year)?
- What options did SDG&E have to "hedge" its retail rates?
- What were prices in the CAL PX block forward market on Jan 15, 2000 and May 15, 2000?
- FERC and the ISO should consider the regional impacts of any price caps implemented in California, such as prices not corresponding to flows

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We Do Not Have All the Answers. Why?

- ISO and PX have a monopoly on data.
- ISO and PX have monopoly on analysis of market power.
- Transparent markets are preferable to opaque markets. Transparency requires data release.
- Open up the books for all to see.

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Status of Data Release

ISO GENERATION

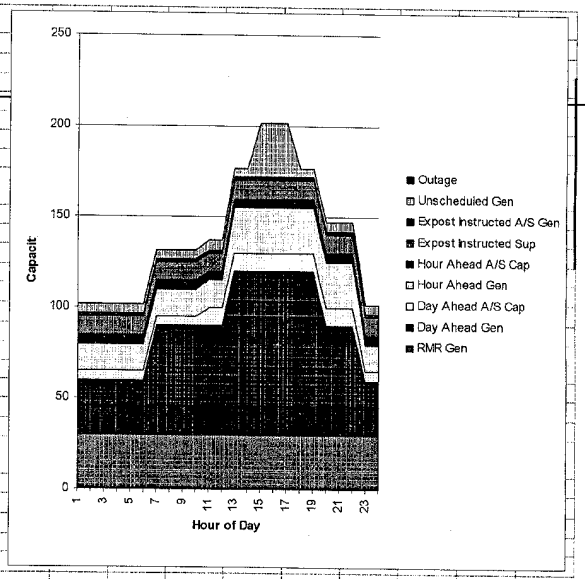
	Allocation*
A	RMR Generation
B	Day Ahead Generation
C	Day Ahead Ancillary Service Capacity
D	Hour Ahead Generation
E	Ancillary Service Hour Ahead Capacity
F	Expost Instructed Supplemental Generation
G	Unscheduled Generation
H	Expost Instructed Ancillary Service Generation
I	Outage/Deration
J	Idle

*Actual Gen = A+B+D+F+G+H

Physical Dimensions
Unit
Plant
Load Zone
Congestion Zone*
System

* Supply and Demand for Capacity, Generation, and Transmission are related at the Congestion Zone Level

Data
Awarded Price-Quantity
Price Quantity Offer Curve



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ISO GENERATION

Allocation	Awarded Price-Quantity					Price-Quantity Offer Curve				
	Unit	Plant	Load Zone	Cong Zone	System	Unit	Plant	Load Zone	Cong Zone	System
RMR Generation										
Day Ahead Generation										
Ancillary Service Capacity										
Hour Ahead Generation										
Ancillary Service Hour Ahead Capacity										
Expost Instructed Supplemental Generation										
Unscheduled Generation										
Expost Instructed Ancillary Service Generation										
Outage/Deration										
Idle										

Possible	
Released	
Partially Released	

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ISO LOAD

Allocation

- Day Ahead Load
- Day Ahead Anc. Serv. Capacity Requirement
- Hour Ahead Load
- Anc. Serv. Hour Ahead Capacity Requirement
- Expost Load
- Actual Load

Physical Dimensions

- Load Zone * Scheduling Coordinator
- Load Zone
- Cong Zone
- System

* Supply and Demand for Capacity, Generation, and Transmission are related at the Congestion Zone Level

Data

- Awarded Price-Quantity
- Price Quantity Offer Curve

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ISO LOAD

Allocation	Awarded Price-Quantity				Price-Quantity Offer Curve			
	Load Zone & SC	Load Zone	Cong Zone	System	Load Zone & SC	Load Zone	Cong Zone	System
Day Ahead Load								
Day Ahead Anc. Serv. Capacity Requirement								
Hour Ahead Load								
Anc. Serv. Hour Ahead Capacity Requirement								
Expost Load								
Actual Load								

Possible
Released
Partially Released

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ISO TRANSMISSION

Allocation
Day Ahead Flow
Hour Ahead Flow
Expost Flow
Actual Flow
Total Day Ahead Capacity
Total Hour Ahead Capacity
Total Expost Capacity
Available Day Ahead Capacity
Available Hour Ahead Capacity
Available Expost Capacity

Physical Dimensions
Congestion Zone Interface*
System

* Supply and Demand for Capacity, Generation, and Transmission are related at the Congestion Zone Level

Data
Awarded Price-Quantity
Price Quantity Offer Curve

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ISO TRANSMISSION

Allocation	Awarded Price-Quantity		Price-Quantity Offer Curve	
	Zone	System	Zone	System
	Interface		Interface	
Day Ahead Flow				
Hour Ahead Flow				
Expost Flow				
Actual Flow				
Total Day Ahead Capacity				
Total Hour Ahead Capacity				
Total Expost Capacity				
Available Day Ahead Capacity				
Available Hour Ahead Capacity				
Available Expost Capacity				

Possible	
Released	
Partially Released	

ECd-000662187

CONFIDENTIAL

Committee on Governmental Affairs
EXHIBIT #A-73

SWIDLER BERLIN SHEREFF FRIEDMAN, LLP
THE WASHINGTON HARBOUR
3000 K STREET, NW, SUITE 300
WASHINGTON, DC 20007-5116
TELEPHONE (202) 424-7500
FACSIMILE (202) 424-7647
WWW.SWIDLAW.COM

JAMES J. HOECKER
jjhoecker@swidlaw.com
Direct Dial: (202) 295-5554
Fax: (202) 424-7643

NEW YORK OFFICE
THE CHRYSLER BUILDING
405 LEXINGTON AVENUE
NEW YORK, NY 10174
TEL (212) 973-0111
FAX (212) 891-9598

March 12, 2002

BY ELECTRONIC MAIL AND HAND DELIVERY

Susan J. Court, Esq.
Lead Counsel for General and Administrative Law
Office of the General Counsel
Federal Energy Regulatory Commission
888 - 1st Street, N.E.
Washington, DC 20426

Dear Ms. Court:

This letter constitutes my response to your memorandum of February 26, 2002, with respect to Question 3 in the February 15, 2002 request by Senator Joseph Lieberman and Senator Fred Thompson to Chairman Wood for information about communications between Commission personnel and Enron.

During my seven years and eight months of service on the Commission, Enron participated in many publicly-noticed natural gas- and electricity-related conferences at the FERC. Although the "Special Instructions" which you received from Senate staff appear to require me to include such public meetings, I have no records that would allow me to identify those meetings, their dates, or their content, with any degree of accuracy. I will therefore assume that the Commission's Office of External Affairs will supply that information, including the record of attendance by Commissioners. I will not include that information here. I will also assume that this is acceptable to you unless you inform me otherwise.

With respect to non-public meetings, I have a calendar identifying my schedule as Chairman from June 1997 to January 2001 (one month is missing). It provides virtually no information on the content or nature of meetings and scant data on the persons in attendance. I can confidently make the following observations, however. First, most of the meetings identified below were "courtesy visits," which were customarily held seriatim with the available members of the Commission. Second, my personal assistants (and occasionally line staff members) usually sat in on those meetings, which they were informational in nature. All my courtesy visits were governed by the strict rule that pending matters were off-limits to discussion. Third, courtesy visits were always initiated by the company, association, or official seeking an appointment. Fourth, I have no record or recollection of telephone conversations or other communications with Enron personnel. Outside my official capacity, I occasionally interacted

socially with Mr. Joseph Hartsoe, an Enron mid-level executive, whom I have known for over 20 years. Finally, I want to make clear that I did not recommend, nor did the Commission ever take, any formal action as a direct result of any Enron meeting.

The list below includes all Enron-related meetings that I can confirm. They occurred between June 1997 and my departure from the Commission in January 2001. I have no recollection or record of specific meetings that I had with Enron before I became Chairman, save one. Mr. Kenneth Lay called upon me in 1995 or 1996. Although I remember his visit, I have no record or memory of the substance of the conversation.

Date	Description
06/26/97	Meeting with Joseph Hartsoe, Vice President for Federal Regulatory Affairs, Steve Kean (title uncertain), and Bill? Butler (title uncertain)
09/11/97	Meeting with Stan Horton, head of Enron's natural gas pipeline operations
01/29/98	Meeting with Jeffrey Skilling (unsure of his title at this time) and Joseph Hartsoe
03/24/98	Meeting with Mr. Joseph Hartsoe
07/23/98	Lunch with Joseph Hartsoe and non-Enron friends
09/18/98	Meeting with Jeffrey Skilling (unsure of his title at this time) and Joseph Hartsoe
09/08/99	Meeting with Stan Horton, head of natural gas pipeline operations, and Donna Fulton, Enron Washington Office
09/22/99	Meeting with Jeffrey Skilling and Joseph Hartsoe
09/18/00	Meeting with Joseph Hartsoe
09/20/00	Sat at the luncheon head table with Kenneth Lay, Chairman and CEO, Governor Knowles (Alaska), Governor Taft (Ohio), and others, at the Governors' Natural Gas Summit, Columbus, OH
10/19/00	Meeting with Gas Industry Standards Board (probably included Stan Horton, head of GISB at the time)

Date	Description
01/09/01	Meeting at the Treasury Department, convened by the White House Council of Economic Advisors, Gene Sperling, and presided over by Secretary of the Treasury Lawrence Summers and Secretary of Energy Bill Richardson. Between 30 and 50 people were present, including Kenneth Lay and possibly one or two other Enron personnel. The purpose of the meeting was to find solutions to California's electricity crisis. Governor Gray Davis and others in leadership in California were in attendance.
01/13/01	Meeting on California issues with attendees of January 9, 2002 meeting. Kenneth Lay, other industry leaders, and California officials participated by video conference from Sacramento.

Thank you for your attention to this difficult matter.

Sincerely,

James J. Hoecker

JJH/mch

3069882.1

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Committee on Governmental Affairs
EXHIBIT #A-74

Progress Toward Deal to Cut Power Cost
D.C. energy talks run late into night

Carolyn Lochhead, Chronicle Washington Bureau
Wednesday, January 10, 2001
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URL: http://sfgate.com/cgi-bin/article.cgi?file=/chronicle/archive/2001/01/10/MN46278.DTL

Washington -- Emerging at midnight from a seven-hour energy summit with top Clinton administration officials and key players in California's electricity crunch, Gov. Gray Davis declared progress in securing long-term power supplies "at a very attractive rate."

While Davis and the principles at the meeting issued only a vague statement outlining a "need for cooperation," comments from the governor and Energy Secretary Bill Richardson indicated that the state will press energy producers to extend long-term power contracts to the state's big utilities. That would lock in much lower rates for electricity than utilities have been paying.

"All sides gave a bit," Richardson said. The statement added that long-term purchases of power could be made "possibly by the state," rather than the utilities alone.

The meeting came just one day after Davis blasted power suppliers for price gouging and threatened a state takeover of power-generating facilities in the state if they fail to lower prices.

Yesterday's meeting, arranged by White House economic chief Gene Sperling, was the first to bring together all the major players in the state's energy crisis. Among those attending were executives from the utilities and the out- of-state power generators, leaders from both parties in the California statehouse, along with Treasury Secretary Lawrence Summers and Energy Secretary Richardson.

Davis said the participants agreed to set up technical working groups that will start meeting in Washington today, and that the principals will meet again over the weekend at a location yet to be determined.

"We worked for seven hours on this issue," Davis said. "We made progress, particularly on the important issue of long-term contracting to bring down the rates, and ensure reliable power at a very attractive rate."

He called the long-term contracts -- in which power generators would agree to lock in a fixed rate to Pacific Gas and Electric Co., Southern California Edison and other utilities -- "the key to the long-term solution of this problem."

"If we can assure Californians there's a reliable source of power, at an attractive low rate, then I think they can see light at end of the tunnel," Davis said.

Davis flew to Washington for the summit one day after calling deregulation of California's power system "a colossal and dangerous failure."

PG&E and Southern California Edison are caught in a price squeeze between regulated consumer energy prices and deregulated wholesale prices -- a situation that threatens the utilities with bankruptcy.

The two big utilities claim they have lost more than $11 billion and the state is beset by power shortages. Private power companies with generating plants, meanwhile, have profited from huge price spikes.

PG&E spokesman Shawn Cooper said the utility only has three weeks of credit left to pay for power, and that its bond rating has fallen to just above junk grade. Cooper said financial markets would be looking for positive results from the meeting that could have a big affect on the company's ability to borrow.

Davis scheduled no meetings with President-elect Bush, who will take office in just 10 days.

About 25 people attended yesterday's meeting, including PG&E Chairman Robert Glynn Jr.; Ken Lay, chairman of Enron, a big power producer; and James Hoecker, chairman of the Federal Energy Regulatory Commission.

Davis has pressed FERC to impose price caps on wholesale power prices, but the agency has refused, arguing that caps would backfire by discouraging suppliers from sending electricity to California.

The federal government has little latitude over addressing California's energy problems, a fact acknowledged by California state Senate President John Burton, D-San Francisco, who left the meeting after four hours saying "I don't know if the federal government is fully relevant" to the crisis.

But Assembly Minority Leader Bill Campbell said the legislators are "heading back to California," because, "we have work to do in the Legislature now, some of it related to implementing what we discussed here tonight." None of the participants would offer any concrete details of what those measures might be.

The statement outlined five "crucial elements of a solution," including "the willingness of generators . . . to provide on a short-term basis forbearance" of payments owed by PG&E and Southern California Edison.

It also cited the need to find "satisfactory approaches" to the debt accumulated by the utilities "consistent with contractual obligations, which are in the public interest."

Stanford University economist Frank Wolak, who among many economists has been pushing state utilities to adopt long-term contracts for energy supplies, said California's current problem is that the partial deregulation of the electricity industry left the state "halfway between competition and regulation, and that's the worst place to be.

"Either you have to go all the way back to regulation or all the way to competition," Wolak said, "but standing in the middle is like standing in the middle of a busy freeway: the longer you stand there, the greater the chance of being run over."

The state's utilities have been buying power on the short-term, or "spot" market, at exorbitant rates. PG&E spokesman Cooper said the company's bill for power in December alone was $1.7 billion, while it collected $70 million from consumers.

The state recently granted a 9 to 15 percent rate hike, or one penny per kilowatt hour, from 5.5 cents to 6.5 cents, but the utility is paying 40 cents per kilowatt hour for that power.

Bush spokesman Ari Fleischer said neither Davis nor any of his officials requested a meeting with the president-elect, who will replace the White House attendees at last night's meeting in less than two weeks.

Fleischer said Davis and Bush spoke about two weeks ago. "There are some real concerns in California and we need to work together to address them," Fleischer said.

But many of the big power suppliers that Davis has threatened are located in Bush's home state of Texas.

Many Republicans are philosophically opposed to such interventions, and also are in no hurry to aid Davis, a Democrat whose political star was rising until the electricity crisis.

Sen. Phil Gramm, R-Texas, vowed to "vigorously oppose" federal intervention to "take California's politicians off the hook."

"California's politicians," Gramm charged, "failed in refusing to build new power plants for a decade while population and demand exploded."

E-mail Carolyn Lochhead at clochhead@sfchronicle.com

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Committee on Governmental Affairs
EXHIBIT #A-75

Advancing Electric Competition in the Wake of California

Enron's Campaign to Affect Policy and Public Opinion

February 5, 2001

Team Enron

Rick Shapiro
Janel Guerrero
Campaign Managers
Quinn Gillespie & Associates
Steve Kean
Dave Delainey
John Lavorato
Jim Steffes
California Team
Paul Kaufman
Sue Mara
Jeff Dasovich
Sandra McCubbin
Washington, DC Team
Linda Robertson
Communications Team
Mark Palmer
Karen Denne

The Challenge

- Isolate California and communicate a market-based message
- Retain a market-based electricity structure in California
- Minimize California impact and Governor Davis' message across the west
- Facilitate federal action: FERC and Congress
- Identify and manage potential energy crisis in other states
  - New York
  - Florida
  - Others?
- Refine and increase public affairs effort among
  - policy makers
  - the media
  - opinion makers
  - electricity consumers

Major Themes

- Open Access: Finish the job of creating competitive wholesale electricity markets across the U.S.
- Ease the process for siting and interconnection of new generation
- Price caps don't work
- Encourage risk management/hedging strategies for consumers and utilities
- Promote customer choice
- Financial stability of California utilities is imperative
- Enron as a model and solution to the energy crisis

ECp000061968

Isolate California

Objectives

- Assure financial stability of utilities
- Retain direct access
- Encourage market-oriented demand-side management response
- Reform siting/permitting laws and regulations
- Preserve wholesale market and necessary institutions (Cal ISO)

Resources

- Team Enron
- California lobbyists: Hedy Govenar and Bev Hansen
- Enlist other allies and external resources

Framework for Meeting Objectives

- Office of the Governor -- develop more support for market-oriented solutions
- CA Legislature -- continue to educate and build support network as additional legislation moves
- Regulatory -- minimize involvement in the process

ECp000061969

Western Region

Objectives

- Promote major themes
  - Open Access
  - Price caps don't work
  - Ease process for siting and interconnection of new generation
  - Customer choice
  - Enron as a model and solution to the energy crisis
- Educate Policy Makers

Resources

- Team Enron
- Existing western lobbyists
- Other resources?

Framework for Meeting Objectives

- Media/public affairs effort
- Solicit third-party advocates

Washington, DC

Objectives

- Increase Congressional activity to propel FERC into acting on open access issues
- Ensure Congressional action is positive and/or neutral
- Manage impact of outside influences on FERC
  - Administration, Congress, Think-Tanks, Academia, Press
- Educate policy makers
  - Executive and Legislative
- Educate the press

Resources

- Team Enron
- Quinn Gillespie and other lobbyists
- Solicit support from other strategic partners

Framework for Meeting Objectives

- Take inventory of previous Congressional outreach

Washington, DC (cont.)

Framework for Meeting Objectives (cont.)

- grow base target list
- neutralize foes
- increase visibility among allies

- **Tier 1 meetings**
  - Congress: House Leadership
    - Speaker Deny Hastert (R)
    - Majority Leader Dick Armey (R)
    - Majority Whip Don Nickles (R)
    - Minority Leader Tom Daschle (D)
    - Chairman Billy Tauzin (R)
    - Chairman Frank Murkowski (R)
    - Senator Larry Craig (R)

Washington, DC (cont.)

- **Tier 1 meetings (continued)**
  - White House staff
    - John Bridgeland, Director White House Policy Council
    - Joel Kaplan, Special Assistant to the President and Assistant to the Deputy Chief of Staff for Policy
    - Andrew Lundquist, Director of National Energy Policy Development Group
  - Department of Energy
    - Secretary Spencer Abraham
  - Department of Commerce
    - Secretary Don Evans
  - Department of Treasury
    - Secretary Paul O'Neil
  - FERC
    - Commissioner Curt Hebert

Washington, DC (cont.)

- **Tier 2 Meetings**

Senate Influencers/Leaders

- Senator John McCain (R)
- Senator Jon Kyl (R)
- Senator Gordon Smith (R)
- Senator Conrad Burns (R)
- Senator Ron Wyden (D)
- Senator Patty Murray (D)
- Senator Diane Feinstein (D)
- Senator Maria Cantwell (D)
- Senator Byron Dorgan (D)
- Senator Chuck Hagel (R)
- Senator Mary Landrieu (D)
- Senator Jeff Bingaman (D)
- Senator Charles Schumer (D)

House Influencers/Leaders

Rep. Joe Barton (R)
Rep. Michael Bilirakis (R)
Rep. Cliff Stearns (R)
Rep. Jim Greenwood (R)
Rep. Chris Cox (R)
Rep. Richard Burr (R)
Rep. Ed Whitfield (R)
Rep. Roy Blunt
Rep. Dick Gephardt (D)
Rep. John Dingell (D)
Rep. Rick Boucher (D)
Rep. Ed Markey (D)

ECp000061974

Washington, DC (cont.)

Framework for Meeting Objectives

- Media outreach - earned and paid
- "Think-tank" outreach
- "Influencers" outreach (grasstops)

ECp000061975

New York and Other States

Objective

- Promote major themes
- Educate policy makers
- Educate ENA and EES customers
- Anticipate crisis before they occur and induce positive policy response

Resources

- Team Enron
- ENA and EES
- New York lobbyists

Framework for Meeting Objectives

- Editorial board meetings
- Letters with major themes to policy makers
- Coordination with ENA and EES power trading desks
  - Integrate major themes into weekly newsletter sent to ENA and EES customers
  - Participate in conference calls with ENA and EES regarding northeast region

Media Plan

- Quinn Gillespie & Associates LLC
  - Government and public-affairs focused effort
- Opinion research and polling
- Strategy and development of themes
  - Identify where deregulation was done correctly
  - Enron as a model and solution to the energy crisis
- Managing information flow
- Consumer education efforts
  - town hall meetings with CA delegation allies
- Earned media campaign (national)
- Paid media campaign (national)
- Internet communication effort
- Assistance with coalition building and member recruitment
- Coalition management
- Development of materials
  - turnkey kit for 3rd-party advocates

Media (cont.)

- Earned media
  - Reporters who cover energy issues
  - Trade publications
  - Beat reporters in Washington, DC
    - Bureau of National Affairs
    - Congressional Quarterly
    - National Journal
- Editorial boards
- Key columnists
- Media in battleground states
- Television outlets

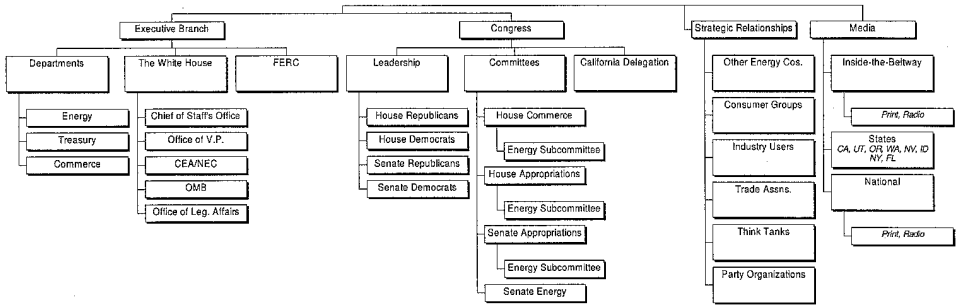
Media (cont.)

- Paid Media
  - Redefining the deregulation issues through a paid media campaign
    - Inside-the-beltway publications such as Congress Daily, CQ Monitor and periodicals such as Roll Call, The Hill, The Weekly Standard and The New Republic are cost-effective venues for target audience.
    - Advertising effort that reaches legislators, regulators, congressional staff and the media

Media (cont.)

- Execution of public affairs effort
  - Working press shop
    - Quinn Gillespie
    - Enron Public Affairs
  - Speaking engagements
  - Editorial board meetings
  - Op-eds
  - Cultivating columnists
  - Events

Target Audiences



Identification and Management of Evolving Issues

- EES commercial exposure in California
- Enron as "government-in-residence" in Washington, DC
- Corporate profiteering issues
- Potential relaxing of environmental laws and regulations blamed on Bush Administration
- Summer electricity prices

Timeframe

- Stabilizing California -- immediately
- Education of policy makers in the west and in and New York -- February/March/April
  - New York meeting of market-participants committee tentatively set for February 13th regarding coordinated/common message throughout the northeast
- FERC and Congressional action by October
- Media schedule to be rolled out February 12

Conclusion

Implementing a focused campaign to stabilize the fallout from California, to promote competitive markets and improve public perceptions

000188

Committee on Governmental Affairs
EXHIBIT #A-76

RECORD TYPE: PRESIDENTIAL (NOTES MAIL)

CREATOR:Andrew D. Lundquist

CREATION DATE/TIME: 4-APR-2001 10:57:14.00

SUBJECT:: Re: ken lay

TO:Ed Gillespie
READ:UNKNOWN

CC:Kjersten S. Drager
READ:UNKNOWN

TEXT:
Ed, Actually I have a conflict then. Have someone call Kjersten (456-7050) and set up a time. She'll even move other meetings if necessary but I can't do the Friday 3:30pm. Thanks, Andrew

Ed Gillespie
04/03/2001 03:47:24 PM
Record Type: Record

To: Andrew D. Lundquist/OVP/EOP
cc:
Subject: ken lay

andrew,

thank you again for your call today. as it turns out, ken lay will be in town on friday (participating in a horatio alger award of some kind). would
you be free to visit with him around 3:30? specifically, he would want to talk to you about the following policy:

Fair Transmission Access

In Order No. 888, the FERC attempted to formulate fair terms and conditions of access to the transmission grid for all users. However, the FERC failed to extend its jurisdiction to transmission services bundled together with retail sales. Consequently, distinct rules apply to different parties for use of the same transmission asset and such rules provide vertically integrated utilities with a competitive advantage in wholesale and generation markets.

To achieve robust competition in wholesale power markets, the FERC must actively exercise jurisdiction over all aspects of electricity transmission in interstate commerce and place all uses of the grid under the same rates, terms, and conditions, regardless of whether the transmission service is bundled together with retail sales. Moreover, FERC jurisdiction must extend
to the terms of access applicable to transmission systems owned and operated
by non-FERC jurisdictional entities including Federal Power Marketing Associations (PMAs), states and municipalities.

i promise not to spam you now that i have your e-mail, but thought this worthwhile! best, ed g.

000479

Committee on Governmental Affairs
EXHIBIT #A-77

RECORD TYPE: PRESIDENTIAL (NOTES MAIL)

CREATOR:Ed Gillespie

CREATION DATE/TIME: 3-APR-2001 09:48:54.00

SUBJECT:: barton's bill and some policy questions

TO:Andrew D. Lundquist
READ:UNKNOWN

TEXT:
andrew,

it was great to see you friday. i wanted to let you know, in case you don't
already, that joe barton is drafting legislative language to circulate this week--providing a copy to dems and gops on his subcommittee tomorrow. this
is not "introducing" a bill, but you can reasonably expect that the media will get their hands on it ten minutes after the first democrat does.

joe's folks say they've asked the white house for input by tomorrow if you want it reflected in the draft. (in the interest of full disclosure, my wife cathy is joe's pac director and was his a.a. for ten years--i feel like
a double agent here.)

i am recruiting enron into the energy coalition and getting them actively supporting the administration in this fight. they've asked me to run a few traps.

is there any chance the talking points can touch on open access to the transmission lines as a way to improve reliability, increase competition, and reduce prices. (this is a top priority for them.) i understand the barton bill would make sale of the transmission lines in california subject to open access to an rto, which is consistent with the admin's position.

can you say at this point whether or not the administration will authorize and mandate participation by all transmission-asset owners (including federal utilities, public power and coops) in a pilot program RTO if approved by a supermajority of governors in a Western RTO?

lastly, would you propose granting FERC-backstop authority for transmission siting when a state fails to site needed transmission expansions requested by an RTO within a reasonable period.

thanks, andrew. we're going into the field with a new nationwide poll next week. please let me know if there's anything you would like tested.

best, ed g.

Advancing Electric Competition in the Wake of California

Enron's Campaign to Affect Policy and Public Opinion

May 4, 2001

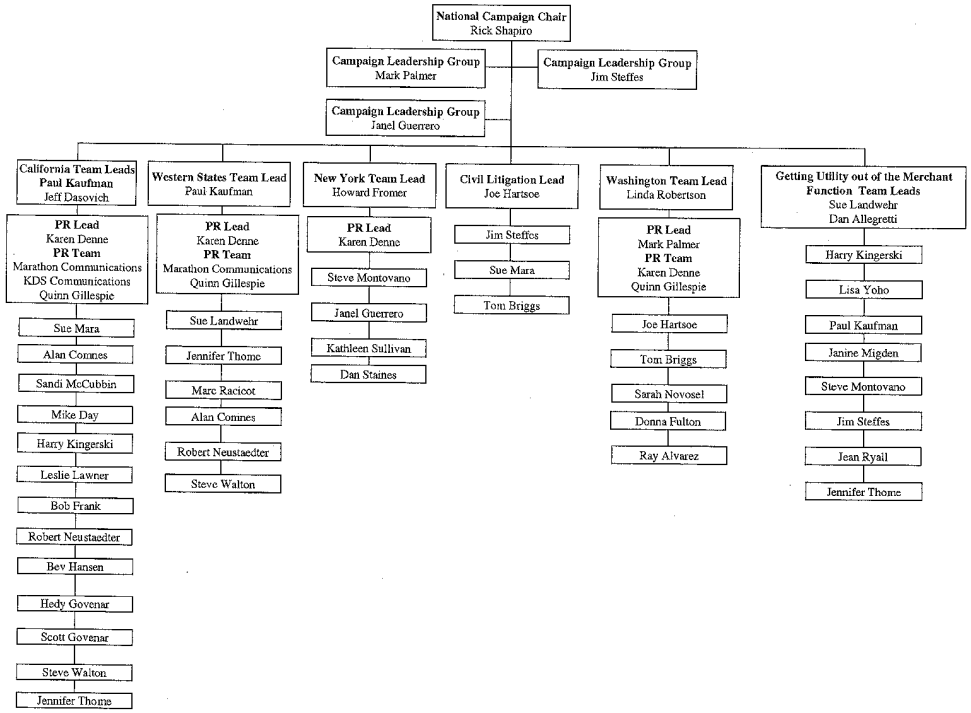
Committee on Governmental Affairs
EXHIBIT #A-78

ECu000003222

Overview

- Team Enron
- Campaign Objectives/Messaging
- Washington, DC
- New York
- Litigation
- Price Risk Management
- Western States
- California
- Measuring Accomplishments
- Conclusion

ECu000003223



ECu000003224

Campaign Objectives/Messaging

- Finish the job of opening wholesale markets
- Limiting fallout from California in order to preserve existing markets and advance the development of competitive electric markets (retail)
- Preserve Choice
- Accelerate generation permitting and siting process
- Prevent unnecessary government intervention
- Accelerate development of Western RTOs
- Increase supply
- Reduce demand
- Oppose price caps
- Price Risk Management

ECu000003225

Washington, DC

- Federal Goals
  - Encourage FERC and the White House to bring the benefits of competition in electricity markets to consumers, improve reliability and develop ways to identify and eliminate market power, thus avoiding further crisis situations like California
  - Facilitate FERC to actively exercise jurisdiction over all aspects of electricity transmission in interstate commerce and place all uses of the grid under the same rates, terms and conditions. This jurisdiction must be extended to cover non-FERC jurisdiction authorities, like the federal, state and municipal entities
  - Encourage the Administration to take all the necessary steps to complete the confirmation process of its FERC nominees
  - Educate Members of Congress and the Administration about the West Coast energy crisis and encourage them to allow the market to work and to take efforts to increase supply and reduce demand. If Congress does not take legislative action, encourage the inclusion of open access and mandated RTO provisions
  - Block price cap legislation and administrative orders

ECu000003226

Washington, DC (cont).

- Elements of Work Plan
  - Meet with Members of Congress
  - Meet with the Cabinet and senior officials in the Bush Administration
  - Deliver briefing papers to Members of Congress and Bush Administration
  - Distribute polling results
- FERC Issues and Initiatives
  - Allow the market to work/increase supply
  - Creditworthiness
  - CAISO board governance
  - Pacific Northwest RTO
  - Encourage forward contracting
  - DSM/Conservation
  - Regional Demand Exchange
- Legislative Initiatives
  - Emergency Measures for Western Power Markets

ECu000003227

New York

- The Problem
  - NYC and Long Island face a tight supply situation this summer
  - Regulators and policymakers are concerned about price spikes and rolling brownouts during peak demand periods
  - News coverage of California's crisis has heightened awareness of energy issues
  - Adoption of various market intervention mechanisms by NY ISO in order to protect customers from price volatility this summer

- The Solution
  - Lobbying effort through Shulklapper & Vacek, PC
  - Formation of coalition/Development of PR initiative
  - Qualitative/Quantitative Research
  - Target opinion elites
  - Development of message
  - Deployment of tactical strategy

Litigation

- The Problem
  - Energy suppliers, including EPMI and EES, have been sued in CA State Court as part of a class action lawsuit for refunds of monies collected for sales into CA through the ISO and CALPX
    - Bankruptcy petition by PG&E – Federal Court
    - Class Action suit – CA State Court/removed to US District Court for Northern District of CA
    - Other class action lawsuits, individual lawsuits and bankruptcy proceedings are possible
- The Solution
  - Work with FERC, Congress and the Administration to consolidate claims before federal forums with an emphasis on FERC
  - Alternatively, ensure that the federal court retains jurisdiction and seek guidance from the FERC under doctrine of primary jurisdiction
  - Participation on creditors' committee
  - Legal department to work with Team Leaders representing all markets

ECu000003229

Price Risk Management Initiative

- Objectives
  - Create commercial opportunities
  - Imbed PRM in the utility/regulatory mind-set
  - Disengage utilities from the merchant function

- Implementation
  - Conduct market, political and regulatory analysis of potential states/utilities to target
  - Develop a comprehensive and articulate message that can be applied to a range of audiences
  - Establish timeline for implementation
  - Target Commissions, Legislators, NARUC leadership and/or committees via presentations, one-on-one meetings, mailings, etc.

ECu000003230

Western States

- Goals
  - Isolate California energy crisis
  - Unify Governors against balkanization of WSCC
  - Educate Governors on potential solutions
  - Support Governors throughout summer months on technical issues

- Implementation
  - Intelligence gathering
  - Availability as an information resource
    - Regular briefings
  - Coordinate with Former Governor Marc Racicot
  - Develop and implement coordinated PR initiative with Marathon/CA
    - Improve relations/coverage among western media outlets
  - Continue association through WGA, RGA, PGE

ECu000003231

California

- Goals
  - Minimize damage to existing markets and create new commercial opportunities where possible
  - Achieve core business-driven objectives identified to date:
    - Maintain direct access
    - Prevent retroactive end to the rate freeze
    - Prevent price caps
    - Enhance open transmission access
    - Streamline siting/permitting
    - Hold the line against retrograde governmental regulation
- Implementation
  - Sacramento
    - Continue lobbying efforts
    - Identification of key legislation
    - Participation in appropriate hearings

ECu000003232

California (cont).

- Implementation
  - CPUC
    - Rate design and cost allocation in light of CPUC rate increase
    - Implementation of AB1X
    - Rate component to make DWR credit-worthy
    - Investigation into gas-related issues
    - DSM/curtailment programs
    - Complaint against SCE & PG&E for payment of negative CTC
  - ISO
    - Failure of governance
    - Market Stabilization plan
    - Allegations of market abuse
    - Balkanization effort
    - Market surveillance

ECu000003233

California (cont).

- PR Initiative
  - Sacramento – KDS Communications
    - Maintain daily contact/relations with Sacramento press corp
    - Identify evolving issues/upcoming crisis
    - Monthly media briefings
    - Rapid response
    - Regular oped pieces
    - Coalition/Association PR efforts as needed
    - Coordination with Marathon Communications
  - Statewide – Marathon Communications
    - Direct Mail Outreach
      - Increase the number of key "grass tops" leaders statewide with whom Enron can engage in dialogue
        - » Community and opinion leaders: businesses, organizations/associations, religious, non-profit, academic
      - Educate + Calls-to-Action
      - Expanding, updating and monitoring responses to direct mail through high-level database

California (cont).

- Statewide – Marathon
  - Executive Level speaking engagements, meetings/conferences, academic forums
  - Coordinate Radio/TV interviews, public affairs and talk shows in key legislative districts
  - Oped placement in CA/Western States
  - Coordinate with EES customers who support our message
  - Further development of web page
  - Rapid Response
  - Development of crisis management component

ECu000003235

Measuring Success

- http://quickplace.2.interliaw.com/california/solutions
  - Library
  - Calendar
  - Task sections
- Daily Calls
- Regularly scheduled coordination meetings
- Endorsement of proposals/calls-to-action

Conclusion

- Team effort
  - Strategic in our efforts
  - Efficient in our actions
  - Successful in promoting real solutions

ECu000003237

Committee on Governmental Affairs
EXHIBIT #A-79

THE WHITE HOUSE
WASHINGTON

FACSIMILE COVER SHEET

DATE:	MAY 22, 2002		
TO:	THE HONORABLE JOSEPH I. LIEBERMAN	228-3792	224-9750
CC:	THE HONORABLE FRED THOMPSON	224-9603	228-3679
FROM:	ALBERTO R. GONZALES, COUNSEL TO THE PRESIDENT		
PHONE:	202-456-2632 FAX: 202-456-6279		

NUMBER OF PAGES (INCLUDING COVER SHEET): 10

MESSAGE:

Confidentiality Notice
The document accompanying this telecopy transmission contains confidential information belonging to the sender which is legally privileged. The information is intended only for the use of the individual or entity named above. If you are not the intended recipient, you are hereby notified that any disclosure, copying, or distribution or the taking of any action in reliance on the contents of this telecopied information is strictly prohibited. If you have received this telecopy in error, please immediately notify us by telephone to arrange for return of the original documents to us.

THE WHITE HOUSE
WASHINGTON

May 22, 2002

Dear Chairman Lieberman:

This letter responds to the Committee's letters requesting information concerning Executive Office of the President (EOP) communications relating to Enron Corporation, as supplemented by our conversations with you and with Committee staff. Throughout our communications on this subject, I have repeatedly assured you of our intention to cooperate with the Committee's investigation. We have devoted substantial time and resources to gathering information responsive to your letter request, and as a matter of comity I am now transmitting to you in the attachment to this letter some preliminary results of our efforts.

Of most significance to the Committee's stated interests, our inquiries thus far have disclosed no instance in which Enron approached any person within the EOP or the Office of the Vice President (OVP) seeking help in connection with its financial difficulties prior to bankruptcy. In addition, the communications we have identified thus far reflect only appropriate and responsible actions by government officials.

As you know, we have undertaken numerous steps in the past several weeks designed to gather information responsive to the Committee's request. These steps have included the circulation of two separate surveys, copies of which were provided to you, to more than 200 individuals in the Executive Office of the President and the Office of the Vice President, including all commissioned officers and other staff members who we believe are most likely to possess responsive information; personal interviews with staff members who indicated they might have responsive information; a search of the White House Worker and Visitor Entry System (WAVES) for records of entry to the White House complex by certain individuals known to be affiliated with Enron; a search of the White House Automated Records Management System (ARMS) for e-mails sent or received by White House personnel that may reflect communications to, from, or about Enron; a search of the National Security Council's classified e-mail system for e-mails sent or received by White House personnel that may reflect communications to, from, or about Enron; and an electronic search of files in the possession of the White House Office of Records Management that are full-text searchable. Because the vast majority of records relating to prior Administrations are in the possession and control of the National Archives and Records Administration, we have focused our efforts on the period between January 20, 2001 and the date of Enron's bankruptcy specified in the Committee's letter, December 2, 2001.

Some of these steps, including our interviews of respondents to the first survey form and our search of WAVES records, have been completed, while others are still ongoing. However, in an effort to begin the process of furnishing information to the Committee on a rolling basis as quickly as possible, we are transmitting in the attachment to this letter the responsive information

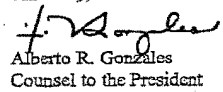
we have collected thus far that is ready for disclosure. We expect to make additional responsive information available to the Committee as further work is completed.

We emphasize that the information in the attachment is preliminary and may be supplemented or amended as we continue to cooperate with the Committee and gather and analyze additional information. You should also be aware that many of the steps described above are subject to certain inherent technological or methodological limitations. For example, WAVES records are imperfect, and electronic searches can only be performed using specified search terms. In all cases, in the absence of guidance from the Committee, we have endeavored in good faith to devise a reasonable approach to the searches we are performing. Should the Committee disagree with our approach, we remain open to considering any suggestions the Committee may have.

The attachment describes communications in three basic categories. The first are communications in which Enron sought assistance from individuals in the EOP or OVP in connection with the company's financial difficulties. The second are instances in which Enron communicated with individuals within the EOP or OVP on matters relating to the eight listed agencies in the Committee's request or relating to issues of law, regulation, or policy affecting Enron's business. The third are instances in which individuals within the EOP or OVP communicated with individuals in federal departments or agencies regarding Enron. A number of these communications have been publicly reported in the past.

We appreciate your acknowledgment at the Committee hearing earlier today that your inquiries are not based upon any suggestion of wrongdoing by White House officials. Please do not hesitate to contact me if you have any questions.

Sincerely,



Alberto R. Gonzales
Counsel to the President

The Honorable Joseph I. Lieberman
United States Senate
Washington, DC 20510

cc: The Honorable Fred Thompson

Attachment

The information in this attachment is preliminary in nature and is based only upon the information-gathering steps taken through May 22, 2002. As further work is performed, the information in this attachment is subject to supplementation or amendment.

Requests by Enron for help from the EOP or OVP in connection with Enron's financial difficulties

None.

Summaries of communications with Enron

On January 29, 2001, Enron was one of approximately 250 signatories to a letter from the Coalition for U.S.-Vietnam Trade to the President urging support for a comprehensive bilateral trade agreement with Vietnam.

On February 7, 2001, Kenneth Lay attended a meeting with Administration officials, including Secretary of Commerce Donald Evans and Assistant to the President for Economic Policy and Director of the National Economic Council (NEC) Lawrence Lindsey, as part of a delegation of approximately 20 top business leaders. The President had a short meeting with the group and made informal remarks concerning the general condition of the U.S. economy and the need for a tax cut. The President sent Mr. Lay and each of the other participants in the meeting a short letter of thanks for their participation the next day, February 8, 2001.

A letter to Secretary of Energy Spencer Abraham dated February 12, 2001, and signed by executives of approximately 20 corporations and trade groups, including Martin D. Sunde, President of Enron Energy Services, was copied to a number of White House officials, including Assistant to the President and Deputy Chief of Staff Joshua Bolten, Deputy Assistant to the President and Director of the Domestic Policy Council John Bridgeland, Chairman of the Council on Environmental Quality Jim Connaughton, Director of the Office of Management and Budget Mitch Daniels, Chief of Staff to the Vice President Lewis Libby, Assistant to the President for Economic Policy and Director of the NEC Larry Lindsey, Executive Director of the National Energy Policy Development Group (NEPDG) staff Andrew Lundquist, Deputy Assistant to the President and Director of Political Affairs Ken Mehlman, and Assistant to the President for Domestic Policy Margaret LaMontagne. The letter and attached budget recommendations supported the development of a National Energy Reliability Initiative.

On February 22, 2001, Kenneth Lay and Linda Robertson of Enron met with then-NEPDG staff director Andrew Lundquist to discuss energy policy issues.

On two occasions, Senior Advisor to the President Karl Rove spoke to Kenneth Lay on the telephone. First, in the early months of 2001, Mr. Rove received a telephone call from Kenneth Lay in which Mr. Lay suggested that Mr. Rove meet with the head of the Environmental Defense Fund. Mr. Rove never scheduled such a meeting. Second, Mr. Lay placed a telephone call to Mr. Rove regarding the President's intention to nominate Nora

Brownell to the Federal Energy Regulatory Commission (FERC). Mr. Lay expressed support for Ms. Brownell's appointment and expressed concern that certain individuals were making efforts to discourage Ms. Brownell from accepting the appointment. Mr. Rove later called Mr. Lay to inform him that no such efforts were taking place.

Clay Johnson, Assistant to the President for Presidential Personnel, had received a letter from Mr. Lay during the presidential transition regarding appointments to the FERC. In the letter, dated January 8, 2001, Mr. Lay suggested qualifications for FERC appointees and recommended seven candidates for FERC, including Pat Wood and Nora Brownell. Mr. Lay also called Mr. Johnson on two occasions in the early months of 2001 to follow up on this matter. By form letter dated March 6, 2001, Mr. Johnson thanked Mr. Lay for recommending Mr. Wood.

Electronic records maintained by the Office of Presidential Personnel (OPP) and other documents reflect that, in addition to Mr. Lay, six other people, including a Democratic Senator, recommended Mr. Wood for FERC. These records also indicate that four people other than Mr. Lay, including the same Senator, recommended Ms. Brownell for FERC. Overall, OPP electronic records reflect that Mr. Lay recommended a total of 21 individuals for appointment in the Administration, of whom only three ultimately received appointments.

Assistant to the President for Economic Policy and Director of the National Economic Council Larry Lindsey had communications with Enron. Dr. Lindsey's job requires him to be in regular contact with industry and outside groups, as well as with relevant agencies, about economic policy issues. As part of his ordinary duties and responsibilities, Dr. Lindsey had a few communications with Ken Lay in the winter and spring of 2001, most likely about the California electricity shortage. On April 6, Dr. Lindsey had a meeting with Mr. Lay, Linda Robertson, Deputy Assistant to the President for Economic Policy Marcus Sumerlin, and Special Assistant to the President for Economic Policy Robert McNally about electricity and bundling issues. Mr. Lay also talked to Dr. Lindsey after the September 11 attacks to state that confidence and investment plans were deteriorating in the wake of the attacks. Enron never asked Dr. Lindsey for help or communicated with him regarding its financial difficulties.

Robert McNally, Special Assistant to the President for Economic Policy, is responsible for domestic and international energy policy issues. Mr. McNally's job requires him to be in regular contact with agencies and outside groups, among others, about energy policy issues. As part of his ordinary duties and responsibilities, Mr. McNally had meetings and telephone communications with Enron representatives in 2001. The main issues discussed in these communications were multi-emissions policy (Enron supported four-pollutant legislation on power plants) and electricity policy.

Meetings attended by Mr. McNally with Enron representatives included the following. On March 6, Mr. McNally may have attended a meeting with a group of people including Enron representative Thomas Briggs. On April 6, Mr. McNally sat in on part of a meeting with Larry Lindsey, Marc Sumerlin, Ken Lay, and Linda Robertson. Ms. Robertson sent an e-mail to Mr. McNally on April 20, 2001. On April 17, Mr. McNally met with Lisa Jacobson and Jeffrey Keeler. On May 23, Mr. McNally met with Ms. Robertson and Richard Shapiro. On June 1, Mr.

McNally met with the Clean Power Group about multi-emissions issues; this group included several outside companies and entities, including Enron. Pat Shortridge, Ms. Jacobson, and Jeffrey Keeler of Enron attended this meeting. On August 15, Mr. McNally met with Mr. Shortridge and another individual who was not from Enron. On October 10, Mr. McNally and Andrew Lundquist met with representatives of Enron LNG, Neal Gerstandt and Emilio Vicens, as well as John Hardy from Enron Corporation; they informed Mr. McNally about an LNG project in Venezuela. (Mr. Lundquist had previously been the Executive Director of the NEPDG staff, but the NEPDG ceased to exist on September 30, 2001, before this meeting took place.)

On March 7, 2001, David Haug, an Enron executive, and one or two other individuals from the private sector met in the Eisenhower Executive Office Building with Andrew Lundquist, the then-Executive Director of the NEPDG staff, to discuss energy policy. Lewis Libby, Chief of Staff to the Vice President, was also present for several minutes.

On April 9, 2001, Thomas Briggs, an Enron representative, was part of a group of utility representatives that met with the staff of the NEPDG to discuss energy policy issues.

On April 17, 2001, Kenneth Lay and Linda Robertson of Enron met with the Vice President for approximately thirty minutes to discuss energy policy and the energy crisis in California.

During the months prior to the release of the NEPDG report, Steve Ruhlen, Deputy Assistant to the Vice President for Legislative Affairs, received a small number of telephone calls from Pat Shortridge, an Enron governmental affairs employee and personal friend of Mr. Ruhlen, seeking information concerning the likely components of the President's energy plan. These conversations were similar to others Mr. Ruhlen had with representatives of other companies and with members of congressional staffs on Capitol Hill. In response to these inquiries, Mr. Ruhlen disclaimed knowledge of specific information concerning the content of the energy plan but expressed a general expectation that the plan would conform to policy positions taken by the President during the 2000 campaign.

On May 15, 2001, as part of a series of meetings leading up to the rollout of the NEPDG report, a meeting was held in the Eisenhower Executive Office Building with approximately 20 representatives of companies or trade groups dealing with renewable sources of energy. Thomas Briggs of Enron attended this meeting at the suggestion of the American Wind Energy Association. The Vice President dropped by the meeting.

On June 28, 2001, the Environmental Protection Agency sponsored a New Source Review stakeholders meeting with the Clean Power Group. Jeffrey R. Keeler attended as a representative of Enron, as did Amy Farrell of the Office of Management and Budget and James Soldano of the Council of Economic Advisers. A number of other companies were also represented at the meeting.

On August 7, 2001, Thomas Briggs, an Enron representative, and one or two other individuals met with Karen Knutson, then-Deputy Executive Director of the NEPDG, and Kirk Blalock, Special Assistant to the President and Deputy Director of Public Liaison, to discuss

difficulties that a German subsidiary of Enron was having with the German government and related perceptions of unfair competition in the German market. Mr. Briggs did not ask Ms. Knutson to do anything on Enron's behalf, and she took no action following the meeting. Ms. Knutson referred Mr. Briggs to the Department of Commerce or the Department of State.

On September 13, 2001, an Enron Executive Vice President, David Haug, had a meeting with Cheryl Oldham of the Office of Presidential Personnel to discuss potential opportunities for obtaining a position with the Administration, primarily in fields other than energy. Nothing came of these discussions, and Mr. Haug was not appointed to a government position. Mr. Haug's resume had been forwarded to the Office of Presidential Personnel during the transition, and Kenneth Lay had sent a letter of recommendation on Mr. Haug's behalf (and on behalf of one additional Enron executive, Jim Bannantine, and a management consultant, Bill Lewis) to Clay Johnson on December 13, 2000. A private attorney representing Enron had also recommended Mr. Haug.

Elizabeth Stolpe, Associate Director for Toxics and Environmental Protection at the Council on Environmental Quality, attended a meeting on October 19, 2001, with members of a group known as the Clean Power Group on multi-emissions issues. The meeting had been requested and set up by the Dutko Group. There were representatives of several industry groups and companies in attendance, including two representatives from Enron, Pat Shortridge and Lisa Jacobson. This was just one of many meetings Ms. Stolpe attended with industry and environmental groups on the multi-emissions issue.

John Howard, then Senior Associate Director of the Council on Environmental Quality, attended two meetings in spring 2001 about multi-emissions with the Clean Power Group, which included representatives from Enron. The meetings were typical meetings with industry groups. Enron wanted the government to regulate CO2, which was also a recommendation of environmental groups. Also, in the fall of 2001, an individual at Enron Windpower spoke to Mr. Howard about a windpower tax credit proposal. This proposal had been included in the National Energy Policy Report issued in May, 2001 and is still under consideration by Congress.

In addition to the information responsive to the Committee's request set forth above, records indicate a number of other White House visits by Enron-affiliated individuals, including on occasion Kenneth Lay, for ceremonial or large group events, such as inaugural festivities, the 2001 Easter Egg Roll, a tee-ball game, remarks to the Horatio Alger Association, and other presidential or vice presidential speeches to large groups of business executives, as well as social and charitable correspondence and events, and correspondence pertaining to appointments other than those the Committee has identified as being of interest.

Summaries of communications with executive departments or agencies regarding Enron

In November, 2001, Chief of Staff to the President Andrew Card was advised by Secretary of Commerce Donald Evans that Kenneth Lay had called Secretary Evans seeking his intervention with credit rating agencies on Enron's behalf. Secretary Evans told Chief of Staff Card that he had declined to intervene, and Chief of Staff Card advised him that he had done the right thing.

Chief of Staff Card also attended internal meetings with government officials from time to time regarding energy policy. At one such meeting, which may have included personnel from departments or agencies outside the EOP and OVP, NEC Director Larry Lindsey may have mentioned Enron in passing in explaining an economic concept relating to the electricity grid.

In late October or early November of 2001, following press reports concerning Enron's rapidly deteriorating financial condition, Joshua Bolten, Assistant to the President and Deputy Chief of Staff for Policy, communicated with Sheila Bair, Assistant Secretary for Financial Institutions at the Department of the Treasury. Mr. Bolten inquired whether a business failure by Enron would likely have systemic effects on the energy or financial markets. He was subsequently informed that the Treasury Department did not believe that such effects would result from a business failure by Enron. Mr. Bolten also may have been advised at some point by Secretary of Commerce Donald Evans that Secretary Evans had received a call from Kenneth Lay seeking assistance with rating agencies, which Secretary Evans had declined to provide. Mr. Bolten did not intervene on Enron's behalf with any department or agency of government.

Secretary of the Treasury Paul O'Neill hosts a weekly economic lunch attended by senior economic policy officials from the Administration, often including NEC Director Larry Lindsey, Secretary of Commerce Donald Evans, Chairman of the President's Council of Economic Advisers Glenn Hubbard, OMB Director Mitch Daniels, and Deputy Chief of Staff Josh Bolten. At one such meeting in October or November, 2001, Undersecretary of the Treasury for Domestic Finance Peter Fisher may have mentioned that he had received a call from former Treasury Secretary Robert Rubin inquiring about the possibility of the Treasury Department providing assistance to Enron.

Last February 1, in response to a letter from Congressman Henry Waxman, Dr. Lindsey advised Congressman Waxman as follows: "Following media reports of Enron's deteriorating condition, my staff and I increased the intensity of our monitoring of the energy and financial markets in an effort to assess the potential systemic impacts, if any, of Enron's failure. As others were undertaking similar monitoring relating to their particular agency missions, some interaction between members of the President's economic team and others in the Administration who were working on similar issues occurred."

In the fall of 2001, Marcus Sumerlin, Deputy Assistant to the President for Economic Policy, spoke to an official in the Department of Treasury about possible systemic risks from the collapse of Enron. Likewise, in the fall of 2001, Philippa Malmgren, Special Assistant to the President for Economic Policy responsible for financial markets issues, assessed the possible impact of Enron's collapse on the energy markets and broader economy as part of her ordinary duties and responsibilities. Dr. Malmgren evaluates the condition of the markets as a regular part of her job. Dr. Malmgren talked to officials at the Commodities Futures Trading Commission (CFTC) about the possible impact of Enron's collapse on the financial markets, including issues relating to counter-party risk. The CFTC had prepared a report about the possible impact on financial institutions, which it faxed to Dr. Malmgren. The next day, the CFTC counsel called Dr. Malmgren and said that it should not have sent the report as there was no need to send it. Dr. Malmgren also communicated with the Department of Treasury during the fall of 2001 on the

topic of the possible impact of Enron's collapse on the markets and the economy. Dr. Malmgren also had communications with Peter Watson from the Overseas Private Investment Corporation (OPIC). Watson discussed the likely consequences of a potential default by India with respect to its obligations on a power plant. On June 20, 2001, Dr. Malmgren also met with Nicholas O'Day from Enron's Tokyo office to discuss issues related to the Japanese economy and markets.

Another of the Special Assistants working for Dr. Lindsey, Robert McNally, communicated regularly with Joseph Kelliher, Senior Adviser for Electricity at the Department of Energy, about electricity and energy policy issues. In the fall of 2001, Mr. McNally had communications with officials from the Department of Energy and Department of Treasury, and also to officials of the Federal Energy Regulatory Commission, as part of the overall effort by the National Economic Council staff to assess the possible impact of Enron's collapse on the financial markets and the economy. At Mr. McNally's request, Rachel Brand, Associate Counsel to the President, sat in on one such conference call with him and other White House officials in approximately late October 2001 regarding the systemic effects of a possible Enron failure. Individuals from the Departments of Energy and Treasury may also have been on the call. Since the Bush Administration took office, Ms. Brand has never spoken to anyone at Enron.

In late 2001, as part of his duties and responsibilities, Carlos Bonilla, Special Assistant to the President for Economic Policy, assessed possible reforms to the pension laws in the wake of the Enron collapse. Mr. Bonilla had conversations with officials of the Department of Labor about pension policy and possible reforms.

Judson Jaffe, Staff Economist for the Council of Economic Advisers, also had communications with Treasury and Energy Department officials regarding Enron in late 2001 as part of the same overall effort to assess possible market impacts of a business failure. In approximately late October 2001, Mr. Jaffe participated in some of the conference calls that were held with Peter Fisher, Treasury Undersecretary for Domestic Finance. Other White House officials on the calls included Randy Kroszner of the CEA and Bob McNally and Pippa Malmgren of the NEC. The subject of the calls was the potential energy and financial market impacts of an Enron bankruptcy. Mr. Jaffe had a follow-up conversation in approximately late November with a member of Mr. Fisher's staff. He also had a follow-up conversation in the same time period with an individual at FERC.

In approximately mid-November 2001, Mr. Jaffe had phone conversations with officials of the DOE's Energy Information Administration regarding the implications of a possible Enron bankruptcy on energy markets.

On or before December 2, 2001, Mr. Jaffe placed phone calls to the Department of Energy to arrange for his attendance at meetings regarding the financial implications of Enron's collapse that were to be held in New York City on December 6, 2001. Mr. Jaffe may have spoken to Kevin O'Donovan of DOE about these meetings.

Beginning at the end of November, 2001, Karen Hughes, Counselor to the President, had occasional conversations and meetings with other press secretaries throughout the executive branch concerning responses to media inquiries on Enron. Similarly, Dan Bartlett, White House Communications Director, spoke to individuals at the Departments of Treasury and Commerce about press stories and media inquiries regarding Enron, although it is likely that these conversations occurred after Enron's bankruptcy on December 2, 2001.

Mr. Bartlett also had a conversation regarding Enron with a personal friend, James Glotfelty, who is Senior Policy Adviser for Electricity at the Department of Energy. Mr. Bartlett may have had this conversation with Mr. Glotfelty in late October 2001. During their conversation, Mr. Bartlett and Mr. Glotfelty discussed recent press stories regarding Enron. Mr. Bartlett did not ask Mr. Glotfelty to do anything regarding Enron, nor was Mr. Bartlett asked to do anything.

On March 6, 2001, the Executive Office of the President hosted an interagency staff meeting to discuss recommendations for nominations to the Commission on Ocean Policy. Ken Lay's name was raised as a possible nominee by the Department of Commerce representative. Subsequently, on March 7, 2002, representatives of the Council on Environmental Quality; the Office of Science and Technology Policy; the Office of Management and Budget; the National Security Council; and Presidential Personnel met to discuss the recommendations raised at the March 6 meeting, and Ken Lay was discussed.

Committee on Governmental Affairs
EXHIBIT #A-80

Kenneth L. Lay
Chairman and
Chief Executive Officer

Enron Corp.
P. O. Box 1188
Houston, TX 77251-1188
713-853-6773
Fax 713-853-5313
Kenneth.Lay@enron.com

January 8, 2001

Clay Johnson
Executive Director
Bush-Cheney Transition Team
1800 G Street
Washington, DC 20270

Dear Clay:

Congratulations on the speed with which you, Dick and others have been able to place high quality individuals in every cabinet post. It is a clear early indicator of a President and a Vice President-Elect who know how to delegate, make decisions and get things done.

I presume you will soon be focusing on members for the various regulatory agencies. One key regulatory agency is the Federal Energy Regulatory Commission and its role is even more important given the recent natural gas and electricity problems.

I am attaching a one-page description of the kind of individuals we think you should be looking for. With those criteria in mind, I'm also attaching a list of potential candidates that we think would do an excellent job on the Federal Energy Regulatory Commission.

I would be happy to discuss this with you or provide any additional information that might be helpful.

Sincerely,

Ken

cc: Vice President-Elect Dick Cheney

Attachments (2)

Endless possibilities.™

000980

FERC Commissioner
Qualifications

We support FERC Commissioners who will embrace a regulatory approach that fosters competitive markets that rely on bilateral contracts to avoid the volatility of short-term spot markets. Any candidate should be a strong supporter of the need for FERC to continue its leadership role in deregulating the electric industry in order to benefit consumers. Such a candidate should support steps to ensure liquidity in energy markets with price certainty for ultimate physical delivery of energy known in advance. Ending residual discrimination in wholesale electricity markets, such as the current native load exception, should be among a candidate's primary objectives. Also essential to competitive electric markets is building a commission committed to placing all transmission in the U.S. under the Commission's jurisdiction. A candidate should support the Commission exercising the exclusive jurisdiction over the reliability of the bulk power system. To this end, a strong candidate is someone committed to working with all the stakeholders and who understands and believes in competitive, transparent and unhindered energy markets. Candidates with a good working relationship with Congress, specifically the Senate Energy and Natural Resources Committee and House Commerce Committee, would be advisable, particularly in the Chairman.

In summary, we believe the following criteria should reflect the profile of a FERC Commissioner:

- Understands the need for Federal leadership and authority to ensure well functioning and efficient interstate bulk power markets;
- Well grounded in free markets (free energy and financial markets), open access, orderly rules of the road;
- Proponent of Commission action to end residual discrimination in wholesale electric markets;
- Willingness to abolish current native load preference under current tariffs;
- Recognized leader and articulate spokesman of energy and financial issues;
- Advocate of secure, competitive and responsible sources and production of energy that serves the needs of the public;
- Strong manager;
- Committed to the Commission's role in information collection, analysis and research on energy data & prices which helps develop informed decisions on long term energy supply and use;
- Comfortable relying on market forces to ensure the provision of safe, reliable and abundant energy (gas and electric).

Specific Candidates

Strong Candidates

Pat Wood	Current Chairman of the Texas Public Utility Commission who worked as an aide to FERC Commissioner Langdon in the early 1990s. Supports free markets. Wood was instrumental in implementing a plan that resulted in the successful deregulation of the Texas electricity market. The Texas experience provides a favorable contrast to California's failed effort.
Nora Brownell	Brownell currently serves as Pennsylvania PUC Commissioner. She is a former deputy executive assistant to Gov. Richard Thornburgh and a banking executive. She supports free markets and was the swing vote enabling Pennsylvania to open its electric markets to competition. Pennsylvania's program is widely regarded as the nation's most successful.
Cathy VanWay	Current counsel to the House Commerce Committee under Congressman Tom Bliley. Cathy has worked for the Committee in this capacity for both the majority and minority. Prior to working for the Committee, Cathy worked for Verner Liipfert. She has drafted pro-free market electricity restructuring legislation.
Phil Moeller	Currently works on energy issues for Senator Slade Gorton. He is not an attorney, but aided in crafting electricity restructuring legislation as a staffer in the Washington State Legislature. Has a Northwest perspective on the hydro-licensing issue. He has drafted pro-free market electricity restructuring legislation.
Richard Glick	Currently serves as Senior Policy Adviser for Electricity and Energy in the Office of the Secretary of Energy who worked closely with stakeholder groups in attempting to reach consensus on and pass electricity restructuring legislation. He is a former staff member for Senator Dale Bumpers and also worked for Verner Liipfert. He has drafted pro-free market electricity restructuring legislation.
McLane Layton	Layton currently serves as counsel on energy issues to Senator Don Nickles. Formerly worked as counsel at the Department of Interior. She has drafted pro-free market electricity restructuring legislation.
Bill Scherman	Former General Counsel at FERC under Martha Hesse where he was pro free markets.

Committee on Governmental Affairs
EXHIBIT #A-81

ENRON
MEMORANDUM

TO: Ken Lay
cc: Steve Kean
Richard Shapiro
FROM: Linda Robertson
DATE: February 12, 2001

You are scheduled to call Clay Johnson today about Commissioner vacancies at FERC. The purpose of this memo is to provide you an update on pending candidates and Enron's discussion with those candidates.

There are presently two vacancies on the Commission. Because only three Commissioners can be members of the same political party and at present there is only one Republican Commissioner, the Bush Administration can appoint two Republicans to the open seats. In addition, the five year term of the three current Commissioners expire: Chairman Hebert (R) 6/30/04; Breathitt (D) 6/30/02; and Massey (D) 6/30/03.

Enron has strongly supported Pat Wood, a Republican, as Commission Chairman. At present, our information in Texas and DC indicates that Mr. Wood intends to accept an appointment by the Bush Administration but has indicated that he would accept the job after he has an opportunity to implement certain parts of the Texas deregulation effort. It is expected that Mr. Wood would be available for a FERC position mid-year.

A number of candidates are said to be under consideration for the second Republican seat at FERC. Enron has on several occasions discussed with transition and now Bush Administration officials the candidacy of Nora Brownell as our first pick for the second open seat. As of last week, we heard reports that, while Brownell is under consideration, mostly on the strength of Enron's interest, she is not supported by Governor Tom Ridge. Governor Ridge is said to be pushing the candidacy of Chairman John Quain (PA, PUC). Although Enron does not favor Mr. Quain's appointment to FERC, we have talked with Bush Administration officials about a possible White House energy position for him.

Other candidates under various stages of consideration (and we believe that most of them have "interviewed" with Clay Johnson) for the second seat are: McLane Layton, Drue Pearce, Judy Walsh, Joe Kelliher, and Joe Garcia. All of these officials are Republicans, save Mr. Garcia. Ms. Layton is supported by Senator Don Nickles. On Friday, at her request, you sent a letter to Vice President Cheney speaking favorably of her qualifications for FERC, though the letter did not explicitly endorse her candidacy. Enron officials have interviewed Joe Garcia, State Senator Drue Pearce (Alaska), and McLane.

It is difficult to gage the strength of a candidate on interviews of this nature, however, we did come away from these conversations with the belief that Drue Pearce was the most forthcoming in our conversations on access issues important to Enron. Sources outside of Enron note that she has no record on these issues, to speak of, and that she has little

technical understanding of the electric industry. Moreover, although Joe Kelliher has not talked directly with Enron about his interest in a FERC position, we have recently worked productively with Joe Kelliher in his new position as Senior Advisor to Secretary Abraham. Rep. Joe Barton is said to be strongly pushing Mr. Kelliher, his former staffer, for a FERC seat.

In your conversation today, we recommend that you express to Mr. Johson that our first preference for the second seat continues to be Nora Brownell. (We are working with our lobbyists in Pennsylvania to mitigate the Governor's alleged concerns with her candidacy.) We also recommend that you explore with Clay possible backup candidates. You and other Enron officials have recently talked to Joe Garcia as a possible "second" Enron choice for the second seat. We understand those conversations have been somewhat reassuring and that his record in Florida does contain encouraging signals on access issues. One argument Mr. Garcia has made is that the Bush Administration and Enron are better off putting him in one of the existing open Republicans seats because this move would free up an additional Republican slot because Mr. Garcia is an Independent. His thinking is that once the Breathitt seat opens in 6/02 a Republican could be appointed because, as an Independent, he does not count against the "no more than three" from one party rule. He further argues that this gambit has a better chance of success if he is appointed now for a Republican seat rather than later for the Breathitt Democratic seat, which in theory Senator Daschle should have a say in appointing. His argument has some merit; there is logic to his sequencing suggestion. However, his argument falls apart if one assumes that Chairman Hebert would leave the Commission upon Pat Wood's selection as Chair, a not too difficult conclusion to reach. Chairman Hebert's likely departure would open yet another Republican seat, which an independent could be appointed to later this year. Under this alternative sequencing, the Breathitt seat could still be converted to a Republican seat.

Where this leaves us in terms of our "backup" candidate to Nora Brownell is picking from a group of candidates about whom we feel tepid at best. **In light of this situation, we strongly recommend that the most important point to make with Mr. Johnson is not pitching a particular backup candidate, although we can do that as well, but instead pitching the need for the Bush Administration to extract a very firm commitment to move forward on open access issues at FERC from their intended nominee.** If we feel comfortable that such a commitment is made, any of the backup candidates discussed above might work.

H:Linda's Memos/2-12-01 FERC Commissioners

EC 000123910

Committee on Governmental Affairs
EXHIBIT #A-82

ENRON

1775 Eye Street, N.W., Suite 800
Washington, DC 20006

First Class

Address Correction Requested

To: Lay Cheney
Briefing Book

ENRON, WASHINGTON
MEMORANDUM

TO: Ken Lay
cc: Steve Kean

FROM: Linda Robertson
Tom Briggs

DATE: April 13, 2001
RE: Meeting with Vice President Cheney

10:00 AM Tuesday, April 17, 2001
The Honorable Richard Cheney
The Vice President of the United States
The White House
1600 Pennsylvania Avenue, NW
Washington, DC 20501
202-456-9095

BACKGROUND:

The purpose of this meeting is to discuss the development of the Bush Administration's national energy policy and to secure the Vice President's commitment to include in the Administration's plan Enron's primary policy interest: open access transmission rules which place all uses of the grid under the same rates, terms, and conditions of the tariff. There are four components to our electric policy: open access, streamlined interconnection, mandatory RTOs and reliability organizations, and placement of public power facilities under FERC jurisdiction.

We have taken numerous opportunities to advocate all four provisions to the Administration. However, for purposes of this meeting, we strongly recommend that most of the discussion center on our core concern: *open access.*

We also recommend that you take the opportunity to convey to the Vice President the imperative of an expedited confirmation of Pat Wood and Nora Brownell. We believe a fully constituted FERC has the potential to mitigate one of the more significant political problems confronting legislative passage of the Administration's energy agenda, namely the call by Democrats and Western state members for price caps.

DISCUSSION:

a) Administration's Proposal
The Administration has declared that our country faces a major energy crisis over the next two decades. This conclusion is based on three challenges they see confronting our

country: (1) demand for energy is rising across the board, particularly for natural gas and electricity; (2) supplies are limited by a regulatory structure that has failed to keep pace with technology and an uncertain political environment discourages investment; and (3) the energy infrastructure is woefully antiquated and inadequate. In addressing these challenges, the Bush energy plan is expected to include legislative changes, executive orders, and regulatory changes to Federal Agencies. We understand that the Administration presently intends to release its plan on May 14, and will follow the plan with a later release of legislative proposals.

While specifics are not available, the Bush plan is expected to call for increased fossil fuel extraction, including on Federal lands; construction of new natural gas and electric transmission facilities; and investment in new power plants and oil refineries. The Bush plan is expected to include many of the clean coal technology provisions of the Murkowski bill, and will contain recommendations for building new nuclear power plants, ANWR development, and relicensing hydroelectric dams. In a departure from the Murkowski bill, which contains nearly $23 billion in energy development tax incentives, the Administration is said to have rejected most of these tax provisions. The plan will also contain provisions on conservation and demand reduction programs, although the Administration has already been criticized for giving this area too little attention in the plan. The Working Group is expected to recommend proposals to advance energy technology, and we have been working with them on specific distributed generation ideas. We have also discussed on several occasions Enron's ideas for a demand buy down proposal, one of the very few proposals that would produce tangible benefits this summer. (See attachment "10" for a full discussion of the Enron demand buydown plan.) Criticisms of the Bush plan are discussed in the political scenario section of this memo.

b) **Open Access and Transmission Grid Reform**

With regard to electrical transmission issues, it is clear that the White House is focusing on capacity and investment issues, including extending the federal right of eminent domain to transmission facilities. However, it is not clear that they are fully committed to our open access issues.

At a meeting with the Electric Power Supply Association (EPSA) on Monday April 10th, Andrew Lundquist and Karen Knutson stated that they agreed with EPSA's position on RTOs, unbundling, open access and federal jurisdiction over transmission. However, they claimed that they were not sure how to achieve those goals politically or through legislation. They did comment that the recent FERC appointments should go a long way toward sorting out open access rules. Unfortunately, many in the EPSA meeting walked away with the impression that neither Andrew nor Karen were fully committed to the open access agenda and perhaps underestimate the strong correlation between investment in infrastructure and the need for fair rules of transmission access.

Their lack of zeal for open access, while totally unacceptable, is understandable given that the West Coast power crisis has presented the Administration with difficult and unique political issues that will have a profound impact beyond energy policy. For example,

everyone is well aware that Republican Senator Smith of Oregon has a difficult election race in 2002 and his difficulties have been exacerbated by the power crisis. Retaining an even Senate or regaining a majority will be a top Republican priority going into the 2002 election. This simple fact may dictate the Administration's approach to energy policy and could result in less than desirable decisions.

The West Coast Energy Crises makes it difficult for policy makers to focus on open access. Nonetheless, Enron's efforts have yielded some results. First, the appointment of Pat Wood and Nora Brownell to the FERC was a significant achievement especially as it was done over the objections of Senator Lott. EPSA staff recently met with Wood and Brownell. They described the candidates' comments on open access as "fantastic." Second, numerous meetings between Enron senior executives and senior White House staff have been held to underscore the importance of transmission restructuring as an integral component of a national energy policy. Jeff Skilling recently met with Secretary O'Neill to make the open access case. Nonetheless, we remain gravely concerned that the Administration has not settled on its political strategy for this debate and this circumstance is leading to inaction or tepid action at best.

c) Price Caps

Although the Administration and the Republicans in Congress are making the right noises about their opposition to price caps, there is great concern within the industry that price caps may be inevitable. At the EPSA meeting, Lundquist stated that he is getting pressure from both Democrat and Republican Members of Congress about price caps in the West. Most interpreted his statement as a warning that price caps may be inevitable.

The most contentious political issue dividing Congressional Democrats and Republicans is energy price caps. Thus far, Republicans in both the House and the Senate (as well as the Bush Administration) have held fast against price caps (or a temporary return to cost-based wholesale rates). *However, Western state politicians are growing increasingly nervous and are getting significant pressure from their constituents to place a temporary cap on prices.* Senator Larry Craig's office made it clear that it is difficult to argue against them especially given that the agricultural community is already hard hit by low commodity prices and lack of water. Senator Craig made the same point recently to Jeff Skilling.

The Democratic Energy Committee alternative bill on energy contains a provision proposed by Senators Feinstein (D-CA) and Smith (R-OR) to establish a temporary cost-based rate (cap) for wholesale electricity prices in the 11 state region of the Western System Coordinating Council. Price caps will only be applied to States that allow its utilities to recover the costs of the cost-based rate through its retail rates. The state PUCs will have the latitude to determine when and how utilities can satisfy this condition. In addition, Senators Feinstein, Smith and Dorgan (D-ND) have proposed legislation that caps prices for secondary pipeline capacity in an attempt to address the El Paso problem.

Given the 50/50 split in the Senate, there is a danger that price cap legislation will gain traction and materialize in legislation on the Senate side. Thus far, Enron has been

successful in arguing against price caps and the Republicans and the Administration seem determined to make price caps an issue that divides Democrats and Republicans.

On the other hand, Senator Smith (R- OR) will be in a tough race in 2002 and the Republicans are in danger of losing the Senate in 2002. In addition, it is not clear whether Senator Murkowski is solidly against price caps or is willing to trade them for drilling in ANWR.

d) **Barton Emergency Energy Legislation**
The Republicans on the House Energy and Air Quality Subcommittee, led by Congressman Barton, have drafted legislation containing short term, emergency measures to alleviate the crises in the Western States comprising the Western Systems Coordinating Council. Such measures include a mandatory connection policy for distributed generation, mobilizing the Federal Emergency Management Agency (FEMA) and compelling the formation of a Western region RTO.

After time for comments from the industry, Barton may introduce the bill at the end of April. The bill is intended as a political response to Democrats and the State of California. Little in the bill could be implemented by this summer and few of the provisions would have any beneficial impact on supply or demand. Thus, there is an open question within the White House whether pursuit of the Barton bill is the correct political tactic. The belief among the industry is that it is going nowhere and it has already served its limited purpose of responding to Democratic demands for action. Although a final decision on its inclusion has not been made, Enron has been initially successful in including its demand buy down proposal in the Barton bill.

POLITICAL SCENARIO:

The energy debate looks to be one of the most politically polarized issues confronted by the new Bush Administration in its first year. Both in the West and nationally the two political parties are rapidly cementing very different approaches to the fundamental energy issues confronting our country, and the Democrats so far seem to be winning the political high ground. In Congress, very different and very partisan legislation has been introduced. Republican Senators are pressing for the adoption of the policies focused on greater oil and gas production. To a large degree, the Democrats and the media have successfully portrayed Republican support for ANWR as the poster child of their policy. Senate Democrats have introduced a duelling legislative plan, which emphasizes conservation, the environment and price caps.

Thus, the Bush Administration now finds itself in the classic, liberal-conservative Democratic-Republican dynamic, and Democrats have successfully defined the dynamic as:

Bush	**Democrats**
Anti-environment	Pro-environment

Higher prices	Lower prices (price caps)
Big oil	Consumers
Drilling	Conservation
Inaction	Action
Dirty	Clean
Deregulation	Deregulation a failure
Protecting market power	Rooting out market abuse

The Bush Administration cannot win an energy policy debate cast on these terms. It must change the dynamic. They need to pick a new fight and in so doing they must "Carterize" the Democrats. In this new prism, the debate would be had along the following lines:

Bush	**Democrats**
Future	Past
Abundant	Rationed (blackouts)
Efficiency	Waste
New Economy	Luddites
Innovation	Regulation
Open Markets	Government ownership
Jobs	Stagnation
2001	1977
New infrastructure	Crumbling assets
Breaking up market power	Status quo

The imperative is to capture the "quality of life" argument. Whoever defines their proposals on those terms wins. What the Bush team needs to do is steal a page from the Clinton new economy playbook and to relegate the Democrats to the Carter "eat your peas" playbook.

a) Open Access

Our challenge is twofold: to persuade the Vice President of the need to better define the political terms and messages underpinning the energy debate and to persuade him that Enron's proposals embody the very core of this message. Our consultant, Ed Gillespie, is separately making these identical arguments to the Bush political team. There are four pieces to our power transmission proposals: (1) Open access; (2) streamlined generation interconnection; (3) mandatory RTOs and reliability organizations; and (4) placement of public power and federal power marketing agency transmission facilities under FERC. By embracing these proposals the Bush Administration could go a long way in solving their political problems in the energy debate and in redefining the terms by which their measures are judged by the public.

There are several political arguments in support of open access which flow from the "quality of life" terms suggested above. First, advocacy of a streamlined and uniform regulatory structure for the transmission grid would allow the Administration to say they are for abundant supplies by getting power from where it is to where it is needed. New supply does not only mean new

drilling. Very conservative numbers suggest full open access to the transmission grid, subject to FERC jurisdiction, will result in an increase of 1-3 percent of additional power supply in the West and 2-4 percent in the East, without building any new generation. In the Western Interconnect, with generation capacity of approximately 135,000 MW, this could result in an increase of 1,350-4,050 MW of power per day. This could be the difference between having the lights stay on or go out.

Under current conditions, due to utilities' monopoly advantages from the native load exception as well as their general lack of motivation to increase throughput, the transmission system is not fully utilized. However, if FERC were to exercise its jurisdiction over the entire transmission system, utilities would no longer have the ability or incentive to withhold transmission from the market. Instead, their profit motive would be to maximize throughput, thus making existing transmission capacity that may previously have been under utilized, now utilized to the fullest extent possible.

Other evidence that open access will increase and better distribute supply is found by looking at the benefits generated by President Bush's decision in Order 636. U.S. customer savings due to natural gas open access since 1985 have exceeded $141.5 billion in nominal dollars, equal to $261 billion today in spending power. Furthermore, in 1987 pipeline load factors were 68 percent; by 1997 the average load factor was 77.5 percent. Gas utilization storage increased 73% over the same period.

Second, open access means innovative and functioning markets, which will in turn stimulate new investment in energy infrastructure. Centralized markets dry up liquidity in forward markets. Without well functioning forward markets, price uncertainty (inability to hedge forward) increases the cost of capital and the cost of new generation.

Third, open access means we will be able to meet future energy demands critical to new technologies. Technology advancement and investment have been the linchpin of the productivity gains in our economy over the past decade. Electricity is a key input to the new economy and the interstate transmission grid is the linchpin of our national electricity infrastructure. Hence a strong and fully open transmission system is essential for future robust economic growth.

Fourth, having FERC complete its responsibility to open the grid instead of leaving it to the legislature solves another political dynamic for the Administration. Democrats argue that deregulation has failed, and point to California as evidence of the failed deregulation experiment. In truth, the only element that failed in our country's deregulation experiment is politicians' distortion of what constitutes deregulation. California was not a deregulation failure. It was a failure of the political system to truly deregulate. FERC has the expertise and political capability to do the job correctly. Instructing FERC to move forward on open access allows the Bush Administration to revitalize the electric energy marketplace and to do so in a sensible and well structured manner.

Finally, open access is about reducing market power. Today's rigid market structure

allows entrenched interests to manipulate the rules of the road and to deny utility competitors access to the system. This inevitably results in tighter supplies, less new investment, and higher consumer prices. Our policies give the Administration tools to refute media and liberal interest claims that the Bush plan is simply about protecting incumbent interests. The Bush plan in fact reduces market power and enhances consumer leverage.

b) FERC Confirmations

Open access can only be completed once a fully functioning FERC is constituted. Therefore Enron's second priority for the meeting is to encourage expedited confirmation of the FERC candidates. Two excellent candidates have been selected. The Bush team now needs to finish the job by getting the candidates in place before the summer.

Western state supporters of price caps have reacted with guarded encouragement about Brownell and Wood. Governor Davis, in fact, recently characterized Pat Wood in a press conference this week as a "kindred spirit". While it is too early to tell, it appears the Western State Senators are not going to use these confirmations as leverage to extract a firm commitment from the Administration on price caps.

This is not to say pressure for price caps has abated. To the contrary, as summer nears, pressure continues to mount in Congress for price cap relief and the hue and cry has altered the debate in two ways. First, it has increased the likelihood that nothing will get done on energy policy. Inaction is an untenable outcome for the Administration. Left unaddressed, our country will see more California's in the next few years and these energy problems will escalate existing downward trends in the economy. Second, the price cap standoff has softened the Administration's willingness to take bold action. As we know from California, half-hearted measures lead to bigger problems down the road.

With Wood and Brownell on board at FERC, the Agency would be able to "release some of the political steam in the system" by adopting more visible pricing steps in Western markets, such as the bid cap measures in place in Texas and the Northeast ISO. Thus, more aggressive action by the FERC on both market power issues and pricing issues would give the Administration enormous political cover and would allow them to redefine the debate on their own terms. Expedited confirmation of Wood and Brownell will thus free up the Administration to achieve a good energy policy outcome.

Some of the political and policy arguments outlined here are supported by polling Enron has in the field right now. We have completed 50% of our "opinion elite" poll. This is a national poll, covering opinion leaders in the media, regulatory field, industry and legislature. When asked about potential solutions to the increased demand in electricity confronting our country, the solution receiving the highest level of support is "removing bottlenecks in the nation's electricity transmission system so power can flow freely from where it is produced to where it is needed." Eighty-one percent supported this option; and the survey sample is 50-50% Republican and Democrat.

Attachments

(1) *Talking Points for Cheney Meeting*
(2) *Enron Position Paper provided to White House Energy Task Force*
(3) *How Open Access Will Help Ensure Adequate Supply*
(4) *Enron Paper on Emergency Measures sent to Barton*
(5) *Enron Western Governor Association Position Paper*
(6) *Smith/Feinstein Price Cap Legislation*
(7) *EPSA Letter on Open Access*
(8) *Summary of Democratic Alternative Billf*
(9) *Summary of Bush Budget Proposals for Energy*
(10) *Enron Demand Buy-Down Proposal*
(11) *LNG Talking Points and Project Description*
(12) *Talking Points on Steel*
(13) *Documents on Carbon Dioxide*

ATTACHMENTS

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#1
TALKING POINTS FOR CHENEY MEETING

Cheney Meeting Talking Points on National Energy Policy

Political Overview

- There has never been a better political environment for governmental action to promote open access and competition in electricity markets. The current energy crisis clearly illustrates the need for more openness of markets and competition to address the supply and demand problems facing the U.S.

- Unfortunately, the Administration's political opponents have done a good job in casting the debate in the traditional liberal-conservative, Republican-Democrat dynamic. Republicans will not win an energy issues debate that takes place on those terms.

- The side that captures the "quality of life" ground will prevail. This means defining the Bush plan as representing steps toward innovation, open markets, new economy, abundant supplies, and new infrastructure investment. It means painting opponents as status quo, government interventionists, producers of blackouts, and stuck in the 1977 "eat your peas" prism.

- The Bush Administration needs to seize the moment and take bold action to address our nation's energy problems. Failure to act strongly will result in the Administration taking ownership of the problems, rather than being seen as acting to correct the mess created by others. With the significant likelihood of other California-like situations in the future, a strong proposal is the best way to seize control of this issue. These steps should be taken as soon as possible.

- As Governor Davis' actions illustrate, half steps simply do not work. The Administration should push FERC to be more doctrinaire and assertive in dealing with these issues.

- For example, in the first Bush Administration, FERC acted boldly with Order No. 636 to promote competition in the natural gas market. FERC must be equally forceful in the electricity market to require open access and promote competition.

The Solutions

- FERC must take action to bring the benefits of competition in electricity markets to consumers, improve reliability and develop ways to identify and eliminate market power, thus avoiding further crisis situations like California.

- To achieve robust competition in wholesale power markets, the FERC must actively exercise jurisdiction over all aspects of electricity transmission in interstate commerce and place all uses of the grid under the same rates, terms, and conditions. This jurisdiction must be extended to cover non-FERC jurisdiction authorities, like the federal, state and municipal entities.

- The Administration should take all necessary steps to complete the confirmation process

of its FERC nominees.

- With these two steps, the Administration can capture the high ground both in political terms and the substantive arena because:

  -Open access would produce a more efficient and plentiful electric infrastructure grid;
  -A fully functioning interstate electric transmission grid better moves supplies from where they are to where they are needed;
  -Eliminating market power and constraints on the transmission grid would yield price reductions for consumers;
  -A fully constituted FERC would allow the new Commission to initiate pricing reviews and rate measures that would obviate the need for legislated price caps;
  -A fully constituted FERC which tackles some of the more difficult political questions removes potential obstacles to legislative action on the Bush energy plan.

)ther Means of Progress

- FERC must develop and enforce standardized, non-discriminatory interconnection procedures.

- FERC should approve only those RTOs with sufficient size and scope and with non-discriminatory terms and conditions for access; and require that all transmission owners participate in an RTO. If structured properly, they will enhance reliability, commercial activities and competition.

- Legislation to create a new "Independent Reliability Organization" ("IRO") to develop and enforce reliability standards.

- Proposals for price caps or cost-of-service ratemaking should be rejected because they will be detrimental to power markets and discourage investment in new supply in covered areas.

- Rather than intervening in the markets by way of price caps, the most effective way to lower prices is to provide for federal siting and permitting authority for the construction of new transmission and generation facilities, which will limit the ability of transmission owners to interfere with the flow of electricity in interstate commerce.

- The Administration should mandate the creation of a regional demand exchange to allow for competition in the reduction of demand by large consumers.

- National energy policy should encourage investment in infrastructure in the Americas to encourage increased access to LNG for the U.S. market. Current gas prices in the U.S. make LNG imports financially viable. There are significant reserves of natural gas in the Americas -- Venezuela, for example -- that can be developed, and the USG can play a vital role both politically and financially in seeing such development occur.

#2
ENRON POSITION PAPER PROVIDED TO WHITE HOUSE ENERGY TASK FORCE

National Energy Policy: Priorities

The 1992 Energy Policy Act (EPA) intended to introduce competition into the wholesale market for electric power by providing transmission access. Events in California and in other parts of the country demonstrated that the benefits of competition have yet to be realized and have not yet reached consumers. To realize the vision set forth in the EPA, the following actions need to be taken:

1. Fair Transmission Access

In Order No. 888, the FERC attempted to formulate fair terms and conditions of access to the transmission grid for all users. However, the FERC failed to extend its jurisdiction to transmission services bundled together with retail sales. Consequently, distinct rules apply to different parties for use of the *same* transmission asset and such rules provide vertically integrated utilities the opportunity to use their transmission assets to disadvantage independent third party generators and wholesalers.

To achieve robust competition in wholesale power markets, the FERC must actively exercise jurisdiction over all aspects of electricity transmission in interstate commerce and place all uses of the grid under the same rates, terms, and conditions. Moreover, FERC jurisdiction must extend to the terms of access applicable to transmission systems owned and operated by non-FERC jurisdictional entities including Federal Power Marketing Associations (PMAs), states and municipalities.

To improve reliability, the FERC has encouraged utilities to combine transmission facilities into large Regional Transmission Organizations (RTOs) and to assign the responsibility for operating RTOs to an independent management team. Properly structured RTOs can ease the movement of power between states and between users within a state, and will enhance reliability, commercial activities, and competition in the energy industry.

However, the FERC has refused to make RTO participation mandatory. This, coupled with the lack of non-discriminatory open access terms, has weakened the RTO initiative. Therefore, the Administration must encourage the FERC to approve only those RTOs with sufficient size and scope and with non-discriminatory terms and conditions for access and to require that all transmission owners participate in an RTO. Finally, the Administration should revise those tax provisions that prevent the transfer of assets to new, stand alone independent, for-profit transmission companies (Transcos).

2. Independent Energy Reliability Organizations

Governance of the North American Electric Reliability Council (NERC) is cumbersome and places new market entrants at a competitive disadvantage. There is a necessary role for FERC oversight of a new Independent Reliability Organization (IRO).

Legislation to establish a new IRO is required. However, the "consensus" reliability language in

the proposed Murkowski bill is ineffective since it establishes an unsatisfactory procedure to resolve conflicts between the IRO and the various RTOs established by the FERC.

Legislation that permits the FERC to delegate authority to develop reliability standards and enforce those standards, establishes an appropriate funding mechanism, includes a limited States' savings clause and provides the IRO participants with anti-trust immunity will accomplish the shared goal of establishing an effective IRO.

3. Wholesale Market Price Caps or Cost-Based Wholesale Rates

The Administration should reject any attempt to re-regulate wholesale power markets by adopting price caps or returning to archaic methods of determining the cost-base of wholesale power. Price caps, even if imposed on a temporary basis, will be detrimental to power markets and will discourage private investment by significantly raising political risk. Similarly, a return to cost-based wholesale rates will be extremely difficult to implement and will effectively negate significant investments made by new market entrants made in reliance on the presence of deregulated wholesale power markets.

4. Interconnection Policy

Competitive generation (including Distributed Generation "DG") and wholesale power markets have been hindered by grid interconnection policies and procedures that restrict new entry. The lack of a uniform and effective interconnection policy creates uncertainty, delay and unnecessary costs in development of new generation capacity and DG technologies. To correct this problem, FERC must develop and enforce standardized, non-discriminatory interconnection procedures.

5. Federal Transmission and Generation Siting Policy

An efficient and reliable interstate wholesale market requires construction of new transmission and generation facilities. Siting and permitting problems have frustrated construction of new facilities. Consistent with rules for certification of natural gas facilities, granting condemnation rights to private parties that have obtained federal authorization to construct facilities can significantly reduce these problems. In addition, Federal Agencies and Tribunal Governments should streamline the regulatory processes to enable expedited construction and efficient operation of energy infrastructure.

6. Demand Reduction Incentives

The Administration should mandate the creation of a regional demand exchange (implemented by mandatory RTOs) that would allow large consumers to post bids for the reduction of demand. If implemented expeditiously, such a mechanism can have an immediate impact in reducing demand this summer.

7. California Power Crisis

The political leadership in California has made limited progress in solving its power crisis. All of the above items would mitigate this crisis.

8. Natural Gas Supply Outlook

There are concerns that natural gas supplies may not be adequate to meet market demand. Yet all studies indicate that remaining economically recoverable resources in North American are ample for decades to come. These supplies can be further supplemented by imported liquified natural gas. This will allow natural gas to continue to provide an increasing share of the total energy needs to the U.S.

#3
EXAMPLES OF PROBLEMS DUE TO LACK OF OPEN ACCESS

How Open Access Will Help Ensure Adequate Supply

April 16, 2001

Open Access Will Result in Additional Power Supply Through Full Grid Utilization
Full open access, including elimination of the native load exception, will result in an increase of 1-4 percent (1-3 percent increase in the west, 2-4 percent increase in the east) of additional power supply, without building any new generation. In the Western Interconnect, with generation capacity of approximately 135,000 MW, on any given day this could result in an increase of 1,350-4,050 MW. This could be the difference between having the lights stay on or go out.

In addition to preventing the most economically priced power from reaching the market, the native load exception can also have the effect of limiting the amount of power that is ultimately wheeled over transmission lines. This is because the utility is not motivated to fully load its transmission lines (either due to competitive reasons or lack of interest), resulting in an under-utilization of the transmission lines. Consequently, at times of peak demand, when supply is most needed, a certain amount of megawatts will most likely not get to market, resulting in unnecessary supply shortages and/or price increases. Furthermore, if transmission reserved for native load is released to the market, it is typically released within-the-day on a non-firm basis only. Scheduling transmission at the last minute results in mistakes and errors, and ultimately an inefficient use of the transmission system. At times of tight power supply, when every megawatt counts, this type of inefficiency cannot be tolerated.

If FERC exercises its jurisdiction over the entire interstate grid, FERC can ensure (through rate incentives or penalties) that utilities maximize throughput so that every available megawatt of power is delivered to those markets most in need of the power.

Open Access Eliminates Grid Balkanization
Supply problems already exist in the west and are expected to spread to other areas of the country. If supply problems do widen, state regulators will be motivated to "close their borders" to exports by ordering their own in-state utilities to reserve for native load use all import and export transmission. Although a clear interference in interstate commerce, the states would be able to require this action because of FERC's claimed lack of jurisdiction over native load transmission.

To prevent state interference in interstate commence, FERC must act now to take jurisdiction over all uses of the transmission grid, including transmission used in bundled retail sales. By subjecting all transmission to FERC's jurisdiction, states will be unable to exercise parochial control over the interstate transmission grid and FERC will be able to ensure that power flows

freely to the markets where it is most needed.

EXAMPLES OF CURRENT PROBLEMS IN TRANSMISSION ACCESS

1. Bonneville Power Authority

The Bonneville Power Authority (BPA) has a separate power-marketing arm. The marketing arm has purchased a significant amount of transmission capacity from its affiliate, BPA. Due to lower hydropower output this year, the BPA marketing affiliate does not need the transmission capacity it has reserved. However, for unknown reasons, the marketing unit has not released the capacity, and the capacity is available only within-the-day on a non-firm (*i.e.*, spot market) basis. By not releasing this capacity, which the marketing unit clearly will not be using for some time in the future, other competitive suppliers who do have power available for sale are prevented from accessing this capacity on a forward basis. If power suppliers are unable to purchase firm transmission on a forward basis, they in turn will be unable to sell power on a firm, forward basis, unnecessarily forcing both power suppliers and power purchasers into the spot market.

2. California Ancillary Services

Power suppliers are permitted to sell ancillary services into the California market, provided that they are able to make within-the-hour adjustments to their bids. Due to inflexible BPA rules, power from the Pacific Northwest that could otherwise be used for California ancillary services cannot be used. (BPA will not permit within-the-hour adjustments on its system.) FERC jurisdiction over all transmission, including the transmission owned by Federal Power Marketing Agencies, would allow FERC to order BPA to amend its rules to permit suppliers to provide much-needed ancillary services to the California market.

3. Poor OASIS Posting

Some operators make their initial ATC determination on a daily basis (and update it only sporadically); others post a single presumptive ATC value for a month or longer. A utility that calculates its initial ATC value based on a daily average will significantly understate availability for some hours of each day while overstating for others. A utility that posts a single value for a month or season (which typically is derived from a worst case scenario for peak load during the period) invariably under reports availability for all but the peak hour. The transmission system use will not be maximized if ATC OASIS postings are understated.

#4
ENRON PAPER ON EMERGENCY MEASURES SENT TO BARTON

Emergency Measures for Western Power Markets

- Make additional supply available
  - Provide clean air act waivers to enable existing power plants to continue to run through summer 2002; preempt existing state and local controls to the extent they prevent continued operation of power facilities through summer 2002.
  - Appropriate federal funds to purchase air emission offsets necessary to enable 10,000 MW of new generation to be constructed in California as well as to offset emissions of existing plants through 2002.
  - Make federal lands available for the siting of new generation and transmission facilities, DOI/BLM/FERC have 60 days to identify and make available sites suitable for the construction of new facilities while not requiring environmental review for the construction or operation of generators on Federal lands for those generators in service before 1/1/2003.
  - Expedite siting throughout the west by establishing a procedure for the Federal Energy Regulatory Commission (FERC) to grant certificates on an expedited basis for construction of generation and/or transmission upon a finding of public convenience and necessity. Once FERC grants the certificate, the applicant may obtain rights-of-way through eminent domain.
  - Loan or extend credit to California for payments to QF suppliers to enable them to continue running.
  - FERC must promulgate within 45 days, rules to require all transmission owners to adopt within 20 days thereafter, standardized and accelerated interconnection procedures for interconnection of generators.
  - Deem that all federal government sites and installations are wholesale customers and these customers may purchase energy and capacity on the wholesale market from licensed suppliers. This will encourage parties to make responsible energy purchasing decisions by contracting in the stable forward markets.
- Reduce demand
  - Appropriate federal funds for a demand buy down program across the Western U.S. (see attached proposal).
  - Appropriate federal funds or provide tax incentives for customers to install real time electricity meters capable of measuring electricity consumption in order to verify reduction in demand.
- Get power and natural gas from where it is to where it is needed
  - Place all uses of the transmission system under the same rates, terms and conditions of the same FERC approved tariff.
  - Establish Western U.S. system operator to manage the flows of power on an open access

basis across the Western United States and include public power entities in Western U.S., including BPA.

  - Develop and implement a non-discriminatory open access tariff (no historic or utility preference in access rights) to be applied across the Western System Coordinating Council.
  - Place all high voltage transmission under the jurisdiction of the FERC.

- Expedited siting authority (with right of eminent domain) for transmission system upgrades
- Appropriate $300 million to upgrade Path 15 between Northern and Southern California.
- Facilitate the removal of bottlenecks in gas transmission facilities subject to State jurisdiction by creating financial incentives and removing regulatory barriers.

Conditions on appropriated funds

- California passes, with 60 days, legislation providing for full funding (through rates or otherwise) of outstanding amounts owed and sufficient to recover, on an ongoing basis, the cost of power to serve California, including power produced by qualifying facilities (QFs).
- California passes, within 60 days, legislation creating a central siting authority with the power to fully authorize the construction of new generation, gas pipelines and electric transmission facilities. The central siting authority shall establish a process for making final determinations on site requests within six months from the filing of an application.
- California passes, within 60 days, legislation that institutes an effective demand "buy downs" that allow large end users to receive wholesale market rates for reducing demand.
- California pass legislation to facilitate the removal of bottlenecks on intrastate natural gas pipelines subject to its jurisdiction.

#5
ENRON WESTERN GOVERNOR ASSOCIATION POSITION PAPER

ACTION PLAN FOR IMPLEMENTING
FINDINGS & PRINCIPLES FOR JOINT ACTION ON
WESTERN STATES POWER MARKET

By Western States Governors:

1. Implement a coordinated media campaign of public service announcements throughout the Western Systems Coordinating Council (WSCC). The announcements would:

A. Emphasize that there really is a severe power shortage in the west that cannot be contained to any single state and which can be managed only by the cooperative and coordinated efforts of all of the eleven western states;

B. Couple that message with recommendations on how to reduce electricity and natural gas consumption, particularly during peak usage hours of the day(, change thermostat and appliance settings, charge batteries at night only, use washers and dryers at night only, shut off unnecessary pilot lights).

2. Direct the regulatory commissions in each of the eleven states to take the following coordinated actions in tandem:

A. Institute a program of demand response for the largest loads (loads possessing interval meters) of each of their public and private utilities by no later than June 1. These programs should be standardized throughout the WSCC and

1. Allow participating customers to reduce their usage or run auxiliary generation and be compensated for their reduced consumption based on market prices; and

2. Permit participating customers to select prospectively either real-time or day-ahead market prices for the reduced consumption.

B. Adopt and have in place by no later than June 1 a WSCC-wide rate plan to cope with drought conditions and the resulting drop in power supplies. The plan should include:

1. Seasonal rates: Electricity rates should be redesigned to fall during off-peak shoulder seasons and increase during peak periods (summer for the southern WSCC and winter for the northern WSCC); and

2. Excess consumption penalties: A reasonable consumption trigger should be set (for example 90 percent of a customer's consumption in the same month during the preceding year) above which rates would progressively increase.

C. Direct public and private utilities to draw up contingency plans for emergency

electricity curtailments of electricity and natural gas, including the identification of essential facilities*e.g.*, hospitals, life-support facilities, certain cryogenic storage facilities) that must not be curtailed.

D. Conduct a 30-day review of their processes for permitting/licensing new generators and to report on recommended regulatory or legislative changes to be promulgated or enacted to streamline and expedite the process.

3. Bring on line by no later than June 1 strategically located mobile standby generators, such as barge mounted generators to serve load on the West Coast.

4.. Direct local communities in their states to review policies and regulations governing the permitted use of small generators in order to identify and remove constraints and impediments to their use.

By the Federal Government:

5. The Federal Energy Regulatory Commission exercises jurisdiction over all aspects of electricity transmission in interstate commerce and place all uses of the grid under the same set of access rules, regardless of whether the transmission service is bundled with generation and distribution source in retail charges.

6. The Federal Energy Regulatory Commission mandates regional transmission organization ("RTO") participation by all transmission-owning entities by December 15, 2001. FERC ensures that these RTOs are of sufficient size and scope to operate efficiently and economically. Properly structured RTOs will ease the movement of power between states and between users within a state, and enhance reliability, commercial activities, and competition in the energy industry.

7. The Federal Energy Regulatory Commission relaxes (1) all non-statutory limitations on the amount of power that qualifying small power production facilities in the WSCC can generate (e.g., the 80 MW cap on geothermal and waste-to-energy facilities and the 30 MW cap on other small power production facilities) and to expedite approval of requests that generation in excess of statutory limits be recognized as EWG generation and authorized to charge market-based rates; (2) waive from May 1 through October 1 the operating and efficiency standards that limit the power that can be generated by qualifying cogeneration facilities.

8. The Secretaries of Energy and Defense conduct a 30-day review of electricity consumption at federal facilities, including military installations and federal laboratories, in the WSCC and implement a comprehensive program of demand reduction at those facilities by no later than June 1.

9. The Secretaries of Energy and State conduct a 30-day review of steps that can remove barriers to electricity and natural gas trade between the WSCC states and Canada and

Mexico. Steps should also be taken to promote the coordination of conservation policies and contingency measures in the event of region-wide emergencies.

10. The Secretary of Energy conducts a 30-day review of federal power resources that could be made available throughout the WSCC this summer from the federal power marketing agencies and possibly other sources and to implement a plan for doing so by no later than June 1.

11. The Federal Energy Regulatory Commission conducts a 30-day review of natural gas infrastructure and storage adequacy, including identification of pipeline bottlenecks and the location of key gas-fired generation facilities.

12. The Federal Energy Regulatory Commission conducts a 30-day review of the operational procedures for each power system operator in the WSCC to identify constraints and increase the efficient dispatch of generators.

13. The Administrator of the Environmental Protection Agency grants temporary waivers between May 1 and October 31 of air emission permit limitations for standby generators in the event that they are needed.

FINDINGS & PRINCIPLES FOR JOINT ACTION ON
WESTERN STATES POWER MARKET

1. There is a single market for electricity in the eleven western United States that comprise the Western States Coordinating Council (WSCC) — the regional body charged with coordinating operations of the power system in those states.

2. There is a severe imbalance between the amount of electricity available and the amount demanded by consumers in the WSCC. This imbalance is driving up prices to unprecedented levels, undermining the economies, not only of the western states, but also the national economy.

3. The causes of this imbalance are many: rapid population and economic growth, not enough additions of newer and environmentally cleaner power generators, extreme weather that has increased both air-conditioning and heating uses of electricity, at the same time that hydroelectric generating capability (critical to the region) has fallen to historical lows due to drought.

4. The supply and demand imbalance — a physical, supply crisis — has become a financial crisis in many parts of the region, particularly in jurisdictions where utilities have had to pay these high prices for power, but have been prevented by regulated fixed electricity rates from recovering these high prices from their consumers. This has made some western utilities insolvent.

5. The supply crisis is being exacerbated by regulated fixed consumer prices that prevent consumers from seeing the supply and demand imbalance in the form of higher prices, which (assuming that their demand for power is at least in part responsive to prices) would encourage them to reduce consumption, particularly in hours when the imbalance is greatest.

6. Because the WSCC, both operationally and economically, is an integrated, single market, which vitally involves all eleven states, no single one of these states can solve the supply and demand imbalance on its own. Restoring some level of equilibrium to this single market will require the joint action of all of these states.

7. Energy policy leadership for the eleven western states resides in the Western Governors Conference. A joint program for restoring balance to the western market should originate with the Conference. Because this market functions in and affects interstate commerce, this effort also needs to be coordinated with the Department of Energy and the Federal Energy

Regulatory Commission (FERC).

8. Because of the long lead time to bring into operation new supplies of electricity, restoring balance in the short term, particularly during the peak air conditioning season this summer, will necessarily require that existing supplies be more efficiently used and demand be reduced.

9. The key to more efficient use of existing supplies lies in coordinating the operation and use of the interstate electricity transmission grid under a uniform set of regional procedures. Today, each transmission owning utility operates its portion of the interconnected grid with only minimal coordination with its interconnected neighbors, and only a small fraction of transmissions on the grid are currently subject to uniform open access rules. Balkanized operation prevents power from flowing where it is needed and forces utilities to hold too much power generating capacity locally in reserve because of the likelihood that long distance transmissions cannot be accomplished or may be interrupted. This can and should be addressed in the near term by (a) requiring transmission owners to surrender operational control of their portion of the interstate grid to an independent regional transmission operator and (b) implementing for all transmissions a single set of open-access rules for reserving and scheduling and paying for uses of the interconnected grid.

10. The most efficient way to reduce electricity demand in the short term is to allow medium to large size consumers see the hourly prices that their utility suppliers have to pay to purchase or generate power, enabling them to respond to rising prices by reducing demand. Consumers that are particularly vulnerable to high prices that reflect scarcity — the poor and the fixed income who are unable to respond to high prices by significantly reducing their consumption — must be protected during the transition back to a balanced electricity market.

11. Ensuring adequate supplies of electricity must be a regional and national priority. In the intermediate to longer term, more supplies of electricity must be added in tandem with reductions in demand. The process for permitting, siting, building and interconnecting to the transmission grid new and environmentally cleaner (than existing fossil fuel) plants for generating electricity needs to be streamlined both nationally and throughout the WSCC.

12. Access to adequate supplies must also be improved by eliminating inconsistent rules and practices that vary by state for accessing the interstate electricity transmission grid. There must be consolidated into one uniform set of national access rules that will enable power transmission to be reserved and scheduled regionally and between

geographically remote sources of generation and consumption. Greater and more uniform connectivity and uniformity in grid access rules will increase supply competition and lessen the vulnerability of any single utility or market area to supply disruptions.

13. Proposals to address the supply and demand imbalance through closing state borders to prevent the export of power must be rejected. The WSCC is a single, interdependent market that cannot be divided into energy island under a policy of state autarky. Efforts to Balkanize this market will fail and exacerbate power shortages throughout the WSCC.

14. Price ceilings on charges to consumers likewise should be rejected. Such ceilings neither reduce demand (to the contrary) nor increase supply (also to the contrary). Rather, consumer prices should begin to reflect what supplying utilities have to pay to generate or purchase power for their customers.

15. It is critical that the Western Governors act jointly and decisively on to implement a program of near-term demand reduction and intermediate and long-term additions of new and cleaner electricity supply capability. It is equally critical that federal authorities that control federal energy supplies and that have jurisdiction over the interstate market coordinate closely with the Western Governors.

#6
SMITH/FEINSTEIN PRICE CAP LEGISLATION

PRICE CAPS AND RETAIL ELECTRICITY RATES
FEINSTEIN/SMITH LEGISLATION

Senators Feinstein (D-CA) and Smith (R-OR) have proposed legislation to impose "temporary" caps on wholesale electricity prices in western electricity markets. (The Western market consists of the 11 states in the Western System Coordinating Council). The price cap proposal is included as part of the Democratic message bill.

In an attempt to lend credibility to this flawed proposal, the Senators propose that caps will only be allowed in States that do not impose retail price limits that prevent utilities from recovering costs of wholesale rates. The proposed legislation creates the illusion of responsibility by requiring California to raise retail rates. However, the legislation will grant California the discretion as to how and when retail rates will be raised. Therefore, the proposal is just another Trojan horse designed to allow California to continue with its irresponsible behavior that now threatens the reliability of its neighbor's power markets.

The proposed legislation would require the FERC to establish a just and reasonable load differentiated demand rates or cost-of-service based rates to be used for the wholesale cap. A "cost-of-service based rate" is defined as being comprised of all variable and fixed costs of producing electricity plus a reasonable return on invested capital. The cap would only apply to State that do not impose retail price limits that prevent utilities from recovering wholesale price costs. In addition, the legislation provides that Federal orders that compel the sale of energy during emergencies cannot be made unless there is a guarantee sufficient to insure that the seller will be paid for the sale. The FERC will determine whether the guarantee is sufficient.

The proposal also provides that a state electric utility commission may prohibit an electric utility in the state from making sales outside the state at any time the state commission believes that the utility is not meeting in-state demand. This provision raises unique Constitutional issues under the interstate commerce clause.

#7
EPSA LETTER ON OPEN ACCESS

epsa™
Electric Power Supply Association
Advocating the power of competition
1401 H Street, NW
Suite 760
Washington, DC 20005
202/789-7200
202/789-7201 fax
www.epsa.org

April 6, 2001

Mr. Andrew Lundquist
Executive Director
National Energy Policy Development Group
Office of the Vice President
Room 283
Old Executive Office Building
Washington, DC 20501

Dear Mr. Lundquist:

The Electric Power Supply Association appreciates the opportunity to meet with you to discuss the development of a national energy policy. EPSA is the national trade association representing competitive power suppliers, including independent power producers, merchant generators and power marketers. EPSA members provide reliable, competitively priced electricity from environmentally responsible facilities in U.S. and global power markets. For your information, we have attached a list of EPSA member companies.

We fully support your effort to prepare an effective national energy strategy. As circumstances in the western wholesale electric power markets are making clear, your work is timely and absolutely vital. The key to a secure energy future is a national energy infrastructure that is robust and efficient.

Competitive power suppliers stand ready to commit hundreds of billions of dollars of private sector investment to increase the supply of electricity (a matrix of announced projects is attached). This new investment in efficient, cleaner technologies is desperately needed nationwide. More and more, however, EPSA companies view their investment decisions as contingent upon the continued development and regulatory reform of the interstate transmission grid. In addition, even with new supply, there will be no remedy to the situation in California and elsewhere without critical changes to transmission regulatory policies and expansion of the transmission grid.

Federal energy policy must recognize power flows from state-to-state and region-to-region on a regular basis. The interstate transmission grid is the linchpin of our electricity infrastructure and regulation of that grid needs to be uniform, predictable and foster regional, if not national, wholesale power markets. Any effective energy policy legislation must address the following:

- **ASSURANCE OF A ROBUST INTERSTATE TRANSMISSION GRID:** The transmission system is only sporadically open to competition and barriers to new plant developers are slowing the infusion of critical investment. Requiring utilities to join Regional Transmission Organizations (RTOs), such as those outlined in FERC's Order 2000, will help in making the transmission grid open and non-discriminatory. RTOs should be large and conducive to competition. Pricing for transmission should preclude "pancaking" (multiple charges as power flows from one transmission system to the next) and all uses of the transmission grid must be required to take service under a single tariff. While Order 2000 presented a positive framework, it is time to take the next step. Congress must act to set a clear deadline for participation by all owners of the interstate transmission grid in robust RTOs. Lastly, expansion of the interstate grid must occur in a timely fashion and fully reflect the best interests of the region.

- **CLARIFICATION OF FEDERAL/STATE AUTHORITY OVER THE INTERSTATE GRID:** The division of authority between state and federal regulatory organizations must be clear and cannot be allowed to Balkanize the wholesale power market. While a state role in retail markets should be maintained, one set of regional or national rules for the interstate electricity transmission grid – with consistent, predictable regulatory oversight at the federal level – is essential. These rules must cover all owners of interstate transmission assets, regardless of whether these assets are held by private companies, public power or the federal government and regardless of whether the transmission service is needed to supply retail customers at a local or distant location.

- **EFFICIENT INTERCONNECTION WITH THE TRANSMISSION GRID:** For companies interested in expanding electric generation capacity (critical to affordable power rates in California and elsewhere), the physical interconnection of the plant to the power grid has become too often the choke point for project development. *Ad hoc* interconnection standards create uncertainty, extensive delays and unexpected or unfair costs for developers. Legislation needs to affirm the right of new generation to interconnect on a non-discriminatory basis to transmission facilities, provide a clear avenue for the federal review of interconnection policies and a timely remedy, if necessary, for any abuse. Legislation also needs to direct FERC to establish reasonable safety, reliability and power quality standards for generation and to establish deadlines for action. Finally, federal legislation is needed to resolve uncertainties associated with the tax treatment of assets associated with interconnection.

While these issues reflect the immediate priorities of the EPSA membership, we also

endorse many of the announced goals of your policy effort. Notably, EPSA member companies include some of the leading developers of renewable power generation. Within EPSA, there is much support for Administration initiatives to encourage fuel diversity and continued investment in a broad range of energy resources.

We hope these views are helpful to you as you resolve the critical questions associated with ensuring our national energy security. We greatly appreciate the opportunity to meet with you or your staff, and are available to meet at any time to discuss these issues in greater detail.

Sincerely,

Lynne H. Church
President

#8
SUMMARY OF DEMOCRATIC ALTERNATIVE BILL

SUMMARY OF DEMOCRATIC ENERGY BILL

On March 22, 2001, Senator Jeff Bingaman (D-NM), Senate Minority Leader Tom Daschle (D-SD) and eight other Senate Democrats introduced a bill with their own solutions to the nation's energy problems. According to the bill's sponsors, this legislation is intended to provide increased supplies of energy balanced with a commitment to increase fuel efficiency, expand investment in R&D, and provide a commitment to link energy and environmental policies so that climate change is addressed along with investing in the country's energy future. One major difference between this bill and the Republican bill is the absence of opening ANWR to oil exploration, an initiative that Democrats fiercely oppose. No Republicans have cosponsored this legislation.

One part of the bill is very similar to the legislation that was introduced by Sen. Dianne Feinstein (D-CA) dealing with the energy crisis in California and the West. The following highlights those measures:

- Requires FERC to impose load-differentiated demand rates or cost-of-service based rates on sales by electric utilities of wholesale power in the western energy market in states that allow electric utilities to pass such rates along to customers or otherwise allow utilities to recover the costs incurred in purchasing electric energy.
- Imposes a ceiling on the rate that can be charged for unused capacity in natural gas pipelines into California.
- Requires FERC, for transparency purposes, to order sellers of natural gas in bundled transactions to disclose the portions of the sale price attributable to the cost of the gas paid by the seller and the cost of transportation price paid by the seller. (Proposed Dorgan bill)
- Creates an industry-run and FERC overseen Electricity Reliability Organization that sets enforceable rules for the interstate transmission grid.
- Requires the FERC to establish a public system for providing current and transparent information on the availability of generating and transmission capacity.

The bill also requires a review of FERC standards for assessing market power in the wholesale power and transmission markets, reducing price volatility, and adequacy of transmission policies.

Also mentioned is a section addressing renewables and distributed generation. The proposed legislation would require the FERC to adopt rules to ensure the interconnection of distributed generation to local distribution facilities.

#9
SUMMARY OF BUSH BUDGET PROPOSALS FOR ENERGY

(Only a hard copy available of this document)

5. ENERGY

Table 5–1. Federal Resources in Support of Energy
(In millions of dollars)

Function 270	2000 Actual	Estimate					
		2001	2002	2003	2004	2005	2006
Spending:							
Discretionary Budget Authority	2,706	3,095	2,773	2,869	3,100	3,199	3,299
Mandatory Outlays:							
Existing law	–4,019	–3,701	–3,296	–3,150	–3,704	–3,626	–3,582
Credit Activity:							
Direct loan disbursements	1,423	1,896	2,246	2,461	2,735	2,817	2,907
Guaranteed loans	152	52	105	100	100	100	100
Tax Expenditures:							
Existing law	2,030	2,100	2,120	1,930	1,620	1,770	1,890

Federal energy programs contribute to energy security, economic prosperity, and environmental protection. Funded mainly through the Energy Department (DOE), they range from protecting against disruptions in petroleum supplies, to conducting research on renewable energy sources, to cleaning up DOE facilities contaminated by years of nuclear-related research activities. The Administration proposes to spend nearly $2.8 billion for these programs. In addition, the Federal Government allocates about $2.1 billion a year in tax benefits, mainly to encourage development of traditional and alternative energy sources.

The Federal Government has a longstanding and evolving role in energy. Most Federal energy programs and agencies have no State or private counterparts. The federally-owned Strategic Petroleum Reserve, for instance, protects against supply disruptions and the resulting price shocks. DOE's applied research and development (R&D) programs in fossil, nuclear, solar/renewable energy, and energy conservation are intended to speed the development of technologies to use energy more cleanly or efficiently, often through cost-shared partnerships with industry.

Energy Reserves

Strategic Petroleum Reserve (SPR): DOE maintains SPR to protect against petroleum supply disruptions and reduce the economic impact of any disruptions. SPR was authorized in 1975, in response to the oil embargoes of the early 1970s. The Reserve now holds 541 million barrels of crude oil in underground salt caverns at four Gulf Coast sites. SPR helps protect the economy and provide flexibility for the Nation's foreign policy in case of a severe energy supply disruption.

In 2001, the two-million barrel Northeast Home Heating Oil Reserve was established. Operated by the private sector, the Reserve helps ensure adequate supplies of heating oil in the event that colder than normal winters occur in the Northeastern United States. The President has committed to continue support for the Reserve.

- In 2002, DOE will maintain its capability to reach a SPR drawdown rate of about four million barrels a day within 15 days and to maintain that rate for at least 90 days.

Applied R&D

DOE's energy R&D investments cover a broad array of resources and technologies to make the production and use of all forms of energy, including solar and renewables, fossil, and nuclear, more efficient and more environmentally sound. The applied R&D programs fund research at DOE's national labs and engage in a variety of partnerships with industry for technology development and deployment.

Energy Conservation: DOE's energy conservation programs, for which the budget proposes $795 million, are designed to improve the fuel economy of various transportation modes, increase the productivity of our most energy-intensive industries, and improve the energy efficiency of buildings and appliances. They also include grants to States to fund energy-efficiency programs and low-income home weatherization. The weatherization program is slated for a significant increase in 2002, as part of the President's commitment to increase funding for the program by $1.4 billion over 10 years. Each of these activities benefits our economy and the environment. Many rely on partnerships with the private sector for cost-sharing and commercialization.

In 2002:

- The world's first automotive-scale (50 kilowatt, (kW)), fully integrated, gasoline-powered fuel-cell system will be delivered by a contractor to the DOE test facility at Argonne National Laboratory. Validation of low-cost ($10/kW) fuel-cell technology will be completed.
- Initial testing will be completed on light trucks with advanced diesel engines that provide a 35 percent improvement in fuel economy while meeting Tier 2 emissions standards.
- The Office of Industrial Technologies will continue R&D partnerships with energy-intensive industries, resulting in an estimated additional $200 million energy savings and productivity gain.
- Local recipients of DOE Weatherization Assistance program grant funds will weatherize approximately 116,000 low-income homes, improving their energy efficiency, and safety, and reducing the residents' energy bills. This is an increase of approximately 51,000 homes over 2001.

Solar and Renewable Resources: Solar and renewable resources programs focus on technologies that will help the Nation use its renewable resources such as wind, solar, and biomass to produce energy. The United States is the world's technology leader in wind energy, with a growing export market and production costs that have fallen dramatically. In addition, photovoltaics (PV) are becoming more useful in remote power applications, and new biofuels plants are being constructed.

Solar and renewable energy will benefit from the Administration's legislative proposal to open a small part of the Arctic National Wildlife Refuge (ANWR) to oil and gas leasing and production. This process will generate bidding bonuses for the Federal government estimated at $1.2 billion, to become available in 2004, which will be made available over a series of years to increase the funding for solar and renewable energy technologies.

In 2002:

- A 100 kW cold-weather wind-turbine, winner of an "R&D 100" award in 2000, will begin experimental operation and testing in an Alaskan village. These turbines are expected to provide reliable power options for small villages and remote installations in extremely harsh arctic environments.
- DOE's biofuels program will complete development of a yeast that can ferment most biomass-derived sugars to meet the cost goals for production of ethanol from cellusic feedstocks.
- The PV program will develop a 17-percent efficient cadmium-telluride thin-film PV cell. This laboratory achievement will be about seven percent more efficient than the best available commercial thin-film PV units of any type.
- The biopower program will complete technical feasibility testing of using closed-loop, short-rotation wood (fast-growing willows) as a dedicated fuel source for power generation at two retrofitted coal power plants in New York State.

Electric Energy Systems: These activities are managed by DOE's Office of Energy Efficiency and Renewable Energy. The programs focus on technical advances in electricity transmission and storage and on the efficiency and reliability of the Nation's electrical grid. The largest activity is in high-temperature superconductivity R&D, which can greatly increase the efficiency of generators and heavy electrical machinery, and dramatically increase the carrying capacity of high-voltage transmission lines.

- In 2002, operational testing will be completed on the world's first commercial-service superconducting utility power cable. This single cable has four times the electrical capacity of the copper cable it replaced, and will supply power to 14,000 residents in a Detroit neighborhood.

Fossil Energy R&D: Fossil fuel energy R&D programs, for which the budget proposes $449 million, help industry develop advanced technologies to produce and use coal, oil, and gas resources more efficiently and cleanly. Federally-funded development of clean, highly-efficient gas-fired and coal-fired generating systems aims to reduce gas emission rates, while reducing electricity costs compared to currently available technologies. These programs also include efforts to discover effective, efficient, and economical means of sequestering carbon dioxide. In the past, the oil and gas program has funded research on activities that had already been commercialized by the private sector. The budget targets funds to projects that will not compete with private sector investment and will improve the longer-term technologies to foster increased, environmentally sound, domestic energy production.

Through a new $150 million Clean Coal Power initiative, the Department will create an industry consortium to direct research toward the most critical barriers to expansion of coal use for power generation in the United States. This cooperative effort, totaling more than $2 billion over 10 years, will require industry to share in the cost of the research work, with the industry share increasing as technologies approach commercial stages. Participating companies will be asked to take part in selection of technologies and evaluate the progress of R&D efforts, with the goal of accelerating development and deployment of coal technologies that will economically meet environmental standards.

In 2002, DOE will:

- develop a new consortium of coal companies, utilities, and generating equipment vendors to direct coal research toward the most important problems faced by the entire industry;
- complete technology evaluations to make available, by 2003, advanced control technologies seeking to achieve cost competitive, deep nitrogen oxides (NOx) reductions in power plant flue gas emissions in response to the Clean Air Act standards, at 25 percent lower cost than available technology; and
- conduct integrated research and field demonstrations of carbon dioxide (CO_2) sequestration in deep, unminable coal seams and depleted oil reservoirs and develop sufficient data to determine reservoir integrity and fate of injected CO_2. If the CO_2 does not escape the formations where it is injected, a safe and economical method of disposal might be developed based on this knowledge.

Nuclear Energy R&D: Twenty percent of our Nation's electricity and about 17 percent worldwide is made today with nuclear power plants. R&D addressing the issues that threaten the acceptance and viability of nuclear fission in the United States will help determine whether nuclear fission can continue to supply increasing amounts of economically-priced energy while reducing emissions.

In 2002, DOE will:

- continue peer-reviewed, competitively-selected R&D projects that address nuclear energy's cost-effectiveness and acceptability, including plant economics, operational safety, proliferation, and waste disposal;
- maintain the advanced radioisotope power system program and facility operations and capabilities for current and future space and national security missions, and explore fission power systems to support future human exploration of space;

- manage its resources and capabilities at Nuclear Energy (NE) managed sites to ensure that the Department can meet its mission requirements, that the NE sites are maintained in a safe, secure, environmentally-compliant and cost-effective manner, and ensure the protection of the workers, the public, and the environment; and
- continue to provide, through the isotope program, a supply of radioactive and stable isotopes for medical and other research.

Environmental Quality

Environmental Management: For the Non-Defense Environmental Management and Uranium Facilities Maintenance and Remediation programs, the budget proposes $592 million to manage part of the Nation's most complex environmental cleanup program, the result of more than five decades of research and production of nuclear energy technology and materials. This will reduce environmental risk and manage the waste at: 1) sites run by DOE's predecessor agencies; 2) sites contaminated by uranium and thorium production from the 1950s to the 1970s; 3) DOE's inactive uranium processing facilities; and 4) the Paducah Gaseous Diffusion Plant operated by the United States Enrichment Corporation. (For information on DOE's Defense Environmental Management program and performance measures, see Chapter 2, "National Defense.")

Office of Civilian Radioactive Waste Management

This office is responsible for ensuring the safe, geologic disposal of radioactive wastes from civilian and defense uses. The budget increases funding for DOE's Civilian Radioactive Waste Management Program in order to help the program stay on schedule toward a formal Site Recommendation in 2002, and a formal License Application at the end of calendar year 2003. In addition, the budget request will enhance the program's effort to achieve a competitive design effort, leading to a robust license application. This design effort will include: 1) an analysis of concepts that span the full range of repository operating conditions, and 2) the development of modular concepts that will lead to outyear budgetary savings for the program.

In addition, the Administration supports efforts to use the nuclear utilities' budgetary receipts for their intended purposes. DOE will submit to Congress an updated report regarding alternative approaches to finance and manage the program by June 30, 2001, as directed by the House report language accompanying the 2001 Energy and Water Development Appropriations Act. DOE will identify in this report models of effective organizations that might benefit the operation of its civilian program.

Energy Production and Power Marketing

Power Marketing Administrations: The Federal Government operates programs that produce, distribute, and finance electric power. The four Federal Power Marketing Administrations, or PMAs, (Bonneville, Southeastern, Southwestern, and Western) market electricity generated at 131 multi-purpose Federal dams and related facilities, and manage more than 33,000 miles of federally-owned transmission lines in 34 States. The PMAs sell about five percent of the Nation's electricity, primarily to preferred customers such as counties, cities, and publicly-owned utilities. The PMAs face growing challenges as the electricity industry moves toward open, competitive markets.

- In 2002, each PMA's goal is to operate its transmission system to ensure that service is continuous, reliable, and balanced—that is, that the system achieves a "pass" rating each month under the North American Electric Reliability Council performance standards. These measures are used industry-wide and indicate the reliability and quality of power provided by utilities.

Tennessee Valley Authority (TVA): TVA is a Federal Government corporation and one of the five largest electric power companies in the country. It generates three percent of the Nation's electric power and transmits that power over its 17,000-mile transmission network to 158 municipal utilities and rural electric cooperatives that serve eight million people in seven States. TVA also promotes economic activity in the area it serves by operating a complex river management system that

provides navigation, flood control, hydropower, water supply, and recreation services.

The Nation's electric power industry is changing so that customers benefit from competition in the industry. To prepare for that change, TVA is cutting its costs wherever possible. In the past four years, TVA has paid down its outstanding debt by over $1.7 billion, roughly six percent.

In 2002, TVA will:

- reduce its debt by an estimated $260 million; and
- keep the navigable waterway TVA manages on the Tennessee River open to commercial traffic 99 percent of the time, up from the 94 percent level TVA achieved in 2000.

Rural Utilities Service: In 2002, the Agriculture Department's Rural Utilities Service (RUS) will make $2.6 billion in direct and guaranteed loans to rural electric cooperatives, public bodies, nonprofit associations, and other utilities in rural areas for generating, transmitting, and distributing electricity. Its main goal is to finance modern, affordable electric service to rural communities. Included within this funding is $100 million loans originated by the private sector and guaranteed by RUS, which will help rural utility borrowers better position themselves in a competitive, deregulated environment. RUS will also make $495 million in direct loans to companies providing telecommunications services to rural communities, and $27 million in grants and $400 million in loans for distance learning, telemedicine, and broadband technology. RUS borrowers continue to provide service in some of the poorest counties in rural America and to the majority of counties suffering from recent population out-migration.

In 2002, RUS will:

- upgrade 187 rural electric systems, which will benefit over 2.8 million customers and create or preserve approximately 60,000 jobs;
- provide more than 50 telecommunication systems with funding for advanced telecommunications services benefiting more than 300,000 rural customers by providing broadband and high-speed Internet access; and
- provide distance learning facilities to 300 schools, libraries, and rural education centers, and telemedicine equipment to 150 rural health care providers, benefiting millions of residents in rural America.

Energy Regulation

The Federal Government's regulation of energy industries is designed to protect public health, achieve environmental and energy goals, and promote fair and efficient interstate energy markets.

Appliance Efficiency Rules: DOE specifies minimum levels of energy efficiency for major home appliances, such as water heaters, air conditioners, and refrigerators, and for commercial-scale heating and cooling components. The initial efficiency standards were established in legislation, and DOE periodically issues rules to revise those standards or to create standards for new categories of equipment.

- In 2002, DOE will issue a final rule for residential air conditioning products for specialized applications, and will begin rulemakings for residential furnaces and boilers, commercial air conditioning products, and electrical distribution transformers—all of which are scheduled to be completed by the end of 2004.

Federal Energy Regulatory Commission (FERC): FERC, an independent agency within DOE, regulates the transmission and wholesale prices of electric power, including non-Federal hydroelectric power, and the transmission of oil and natural gas by pipeline in interstate commerce. FERC promotes competition in the natural gas industry and in wholesale electric power markets.

In 2002, in order to promote competitive, well-functioning energy markets, FERC will measure the response of prices to external conditions in natural gas and electricity, the level of price volatility and changes in price volatility in electricity and gas, and the correlation of commodity prices across regions.

Nuclear Regulatory Commission (NRC): NRC, an independent agency, regulates the Nation's civilian nuclear reactors, the medical and industrial use of nuclear materials and their safeguards, and the disposal of nuclear waste to ensure adequate protection of the public health and safety, to promote the common defense and security, and to protect the environment. NRC international activities support U.S. interests in nonproliferation and the safe and secure use of nuclear materials in other countries. To meet the challenges of a restructured and deregulated electric utility industry, NRC is committed to adopting a more risk-informed and performance-based approach to regulation. This regulatory framework will focus NRC and licensee resources on the most safety-significant issues, while providing flexibility in how licensees meet NRC requirements.

The budget increase accommodates the increasing demand NRC is facing to renew nuclear power plant licenses for an additional 20 years of plant operations, approve reactor license transfers associated with electricity industry restructuring, and support industry initiatives to increase the Nation's electricity supply. In addition, the budget proposes to reduce the burden on licensees to pay fees for NRC expenses that do not provide a direct benefit to them. In 2002, the NRC will recover approximately 96 percent of its total costs through licensee fees, and this will decline to 90 percent by 2005.

In 2002:

- NRC's nuclear reactor strategic goal is to prevent radiation-related deaths and illnesses, promote the common defense and security, and protect the environment in the use of civilian nuclear reactors;
- NRC's nuclear materials strategic goal is to prevent radiation-related deaths and illnesses, promote the common defense and security, and protect the environment in the use of source, by-product, and special nuclear material; and
- NRC's nuclear waste strategic goal is to prevent significant adverse impacts from radioactive waste to the current and future public health and safety and the environment, and promote the common defense and security.

Management and Procurement Reform

Program and contract management at DOE is a priority management objective of the Administration because more than 90 percent of the Department's budget is spent on contracts to operate its facilities. DOE has made insufficient use of competitive, performance-based contracts, and the Administration will increase the use of such contracts for DOE in 2002.

Industry cost-sharing requirements in DOE's applied R&D programs have not been uniformly implemented, and in some programs as few as 20 percent of the projects obtain any cost-sharing. In 2002, DOE's applied energy R&D programs will be implementing a rigorous and consistent cost-sharing policy that applies to all contracts, grants, cooperative agreements, or other funding mechanisms for industry-performed R&D. The cost-sharing policy will provide for an absolute minimum requirement for industry cost-sharing in any project, with graduated steps based on technological maturity and risk, up to a requirement for more than 50 percent cost-sharing for demonstration or commercialization activities. The policy will also include explicit consideration of factors such as estimated time to a commercialization decision, technical progress and change in risk as a result of previous funding phases, and existence of external incentives for industry to perform similar work.

More aggressive and consistent cost-sharing will reduce corporate subsidies, free up funds for other priority projects, and create an internal incentive for industry to terminate projects that are not making adequate progress or are not meeting performance goals.

DOE will also better define its performance measures across the Department, and particularly in its R&D programs. In the past, some performance measures were outside the scope of the Department's influence and gave a distorted vision of the role of the Government and its ability to affect outcomes (e.g., "Ensure a competitive electricity industry is in place that can deliver adequate and affordable supplies with reduced environmental

impact.") Future performance measures will better match the strategic goals identified by DOE.

Tax Incentives

Federal tax incentives are mainly designed to encourage the domestic production or use of fossil and other fuels, and to promote the vitality of our energy industries and diversification of our domestic energy supplies. The largest existing incentive lets certain fuel producers cut their taxable income as their fuel resources are depleted. An income tax credit helps promote the development of certain non-conventional fuels. It applies to oil produced from shale and tar sands, gas produced from a number of unconventional sources (including coal seams), some fuels processed from wood, and steam produced from solid agricultural byproducts. Another tax provision provides a credit to producers who make alcohol fuels—mainly ethanol—from biomass materials. The law also allows a partial exemption from Federal gasoline taxes for gasolines blended with ethanol.

Provide Tax Credit for Residential Solar Energy Systems: Current law provides a 10-percent investment tax credit to businesses for qualifying equipment that uses solar energy to generate electricity, to heat or cool or provide hot water for use in a structure, or to provide solar process heat. No credit is available for non-business purchases of solar energy equipment. The Administration proposes a new tax credit for individuals that purchase solar energy equipment used to generate electricity (PV equipment) or heat water (solar water heating equipment) for use in a dwelling unit. The credit would be available only for equipment used exclusively for purposes other than heating swimming pools. The credit would be equal to 15 percent of the cost of the equipment and its installation. The credit would be nonrefundable and the lifetime maximum credit allowed to an individual would be limited to $2,000 for PV equipment and $2,000 for solar water heating equipment. The credit would apply only to solar water heating equipment placed in service after December 31, 2001, and before January 1, 2006, and to PV systems placed in service after December 31, 2001, and before January 1, 2008.

Extend and Modify the Tax Credit for Producing Electricity from Certain Sources: Current law provides taxpayers a 1.5-cent-per-kilowatt-hour tax credit, adjusted for inflation after 1992, for electricity produced from wind, closed-loop biomass (organic material from a plant grown exclusively for use at a qualified facility to produce electricity), and poultry waste. The electricity must be sold to an unrelated third party and the credit is limited to the first 10 years of production. The current credit applies only to facilities placed in service before January 1, 2002. The Administration proposes to extend the credit for electricity produced from wind and biomass to facilities placed in service before January 1, 2005. In addition, eligible biomass sources would be expanded to include certain biomass from forest-related resources, agricultural sources, and other specified sources. Special rules would apply to biomass facilities placed in service before January 1, 2002. Electricity produced at such facilities from newly eligible sources would be eligible for the credit only from January 1, 2002, through December 31, 2004, and at a rate equal to 60 percent of the generally applicable rate. Electricity produced from newly eligible biomass co-fired in coal plants would also be eligible for the credit only from January 1, 2002, through December 31, 2004, and at a rate equal to 30 percent of the generally applicable rate.

Modify Treatment of Nuclear Decommissioning Funds: Under current law, deductible contributions to nuclear decommissioning funds are limited to the amount included in the taxpayer's cost of service for ratemaking purposes. For deregulated utilities, this limitation may result in the denial of any deduction for contributions to a nuclear decommissioning fund. The Administration proposes to repeal this limitation. Also under current law, deductible contributions are not permitted to exceed the amount the IRS determines to be necessary to provide for level funding of an amount equal to the taxpayer's post-1983 decommissioning costs. The Administration proposes to permit funding of all decommissioning costs (including pre-1984 costs) through deductible contributions. The IRS would continue to determine the amount necessary to provide for level funding of the taxpayer's decommissioning costs. The

Administration also proposes to permit a nuclear decommissioning fund to receive transfers from certain funds that do not qualify as nuclear decommissioning funds for Federal tax purposes (nonqualified funds). Under this proposal, a taxpayer would be permitted to transfer amounts that have been irrevocably set aside in a nonqualified fund pursuant to the requirements of a State or Federal agency exclusively for the purpose of funding the decommissioning of the nuclear power plant. Any portion of the amount transferred that exceeds the amount deducted (or excluded from the taxpayer's gross income) on account of transfers to the nonqualified fund would be allowed as a deduction ratably over the remaining useful life of the nuclear power plant. These proposals would be effective for taxable years beginning after December 31, 2001.

#10
ENRON BUY DOWN PROPOSAL

Federal Demand Buy-Down ("Negawatt") Proposal

Background: Until new generating capacity can built (or until hydro water levels are restored) it is imperative that consumers in the WSCC reduce demand for power. Demand Side Management (DSM) and similar government programs are typically developed in order to encourage conservation. However, such programs often are cumbersome and costly mechanisms that fail to achieve reduction in retail peak consumption. Moreover, bureaucratic demand reduction programs will not be in place by this summer and will not have an immediate affect on consumption.

Many States have encouraged local distribution companies to develop retail demand reduction programs (particularly for large customers) that are designed to be more market responsive by creating a greater financial incentive for customers to reduce load.

Unfortunately demand buy-down programs designed and implemented by local distribution companies are ineffective since they fail to establish a sufficient incentive for large customers to reduce or shift load. This is primarily due to the fact that utilities lack the incentive to encourage customers to reduce demand and are likely to be penalized if customers are able to reduce or shift peak load. Moreover, an effective demand buy down program would require that large end users have access to competitive wholesale power prices, raising concern among utilities that their customers would seek to buy power in the wholesale market in addition to "selling" power through a negawatt program.

In order to realize immediate reductions in demand (without using curtailment programs) the federal government should mandate that local distribution companies develop a mechanism that allows its large retail customers to be compensated at market prices for reduction of consumption or shifting load to off-peak hours.

Elements of an Effective Demand Buy-Down Program: Before discussing the role of the federal government in establishing a "negawatt" program, it is imperative to identify the critical elements of a program and indicate how it can be implemented quickly.

1. Access to Large Retail Loads with Real-Time Metering Capability:

    - Retail Customers within the defined service area of a local distribution company should be capable of reducing load by at least 1 MW per hour. Customers should be allowed to aggregate multiple sites to satisfy this threshold (e.g., all of Cisco's manufacturing sites in a given area). In addition, licensed retail energy suppliers should have the right to aggregate loads from multiple customers. In typical utility programs, the level of participation is set at a much higher threshold (5 MW), which reduces the effectiveness of a demand reduction program.

    - Customers must have the metering and telecommunications equipment in place to allow the local utility to measure consumption in real-time in order to verify that consumption is actually reduced. The measurement interval must be aligned with

the typical settlement periods established in wholesale markets. Since wholesale market pricing is established on an hourly basis (some international markets use 48 half-hourly settlement periods) measurement must be capable of distinguishing consumption by the hour.

- Most large customers that would take advantage of a negawatt program already have real-time metering in place. However, smaller customers willing to participate may not have such metering, which raises the prospect that local distribution companies would prevent or delay installation of such equipment. Moreover, unless there is the possibility of quickly recouping the cost of investing in such equipment, smaller customers will not participate. An effective program that allows customers access to competitive wholesale prices for reducing demand should trigger investment in meters without the need for any state or federal funding or tax incentives.

2. Customer Access to Real-Time and Forward Wholesale Price Signals:

- The fundamental flaw with utility-designed demand reduction programs is that they fail to provide end-users with the flexibility to choose when, for how long and for how much money to reduce demand. A typical program does not provide the end-user with the right to reduce consumption according to its needs – only to the needs of the utility. The demand reduction program for one utility states that the program is triggered only when "it is economic for the [utility] to encourage customers to reduce demand." Moreover, once the utility allows the end-user to reduce load, the reduction can only be made for time periods defined by the utility and at a price dictated by the utility which may be substantially lower than the wholesale market price for a given time period. Moreover, many utilities fail to commit to a firm price for reduction, instead relying on a pricing formula that produces the buy down price after the event.

- An effective demand reduction program would allow customers to tailor the price and scope of any reduction in response to real prices offered by competitors in the wholesale market. A customer would have access to a real-time pricing mechanism (such as Enron Online or similar tools) that shows forward prices for various time slots. Depending on the structure of the market, these slots would typically be hourly, 4-hourly, 16 hourly, daily, weekly, midweek days or monthly. For example, Enron may post an offer to buy –down power at a given location for $100 dollars per MW for 16 hours a day between Monday and Friday. An industrial customer may have the incentive to accept this offer since it could reduce and/or shift production to weekends and off-peak hours. The customer would make a decision about when to reduce its demand, so that the energy it would otherwise consume is sold in the wholesale market. The proceeds received by the customer would pay for the incremental labor and other costs that may be incurred when altering its production to reduce demand. More importantly, the

customer can accept the offer with certainty that the price and timing will not change after-the-fact.

3. Local Distribution Companies Must Facilitate Transactions

- In order for a demand buy-down program to be implemented this summer, utilities would have to agree to "settle" transactions on behalf of its eligible customers. To envision how settlement would work, it is important to understand the implications of such a transaction given the commercial arrangements of utilities.

- Utilities have the contractual purchases or production capability to cover retail load obligations. This would include access to transmission and distribution capacity necessary to deliver to customers. To the extent utilities are not able to cover positions (by reason of force majuere or otherwise), they must either interrupt (a contractual right) or curtail (state sanctioned rationing) retail load.

- Therefore, when a customer decides to reduce load (and makes that decision without regard to the needs of the utility) the utility will have excess power to sell into the open market or to shift to other consumers. If the utility can sell the power in the open market, it may be able to resell the power for more than the price received by the end user.

- The retail tariff for large end users has both fixed and variable components. The fixed component typically includes the costs of assets needed to serve the customer and may include costs for metering, distribution, transmission, generation capacity, debt costs and the rate of return on equity invested in those assets. The variable rate component includes the cost of the energy, which would include fuel costs. A typical demand reduction program establishes a tariff credit for customers that have reduced load below firm levels.

- An issue arises as to whether the fixed and variable components of the tariff should be reduced by the credit at a level in excess of the demand "buy down" purchase price to reflect that the customer has reduced use of the fixed assets. However, given that the customer has the option to use firm capacity at any time, it should still be required to pay the fixed component of the tariff. This should also address any "take – or – pay" obligations that the utility may have with power generators.

- Instead base the level of participation on base consumption during a stated period, such as the previous month, 14 days, same month in previous year, etc. This is the basis for establishing a quasi-property right to sell energy which some would argue they have no right to until they actually consume it.]

- The cost of transmission and distribution is already embedded in the retail tariff

structure. However, the offer to purchase a retail demand reduction may occur at a reference point (location) on the interstate transmission grid that is not included in the cost base of the utility. Therefore, the incremental transmission costs of releasing power at such a reference point must be identified so that the price paid to the end user can be adjusted. For example, a negawatt price of $100 may have been offered outside the utility control area and it would cost $5 to transport the power to the reference point. Therefore, the "netback" to the customer would be $95. The costs of such incremental transmission from common trading points can be easily identified by the utility and disclosed to the retail customer.

- Generally, large customers operate under a State approved generic tariff that is applicable to the class. Some may have separate negotiated contracts with the utility. A generic tariff is basically a contract with terms and conditions that change from time to time upon the approval of the state regulatory body. Therefore, tariff changes necessary to establish a demand buy-down program can be accomplished quickly within the existing tariff change procedures of either the State regulatory process or the FERC process.

- To consummate a transaction the utility must be willing to act as a settlement agent (and collect an admin. fee for doing so). So long as a utility is revenue neutral (or better), it should have no qualms about acting in this capacity. Acting as an agent, the utility would do the following:

1. At the direction of the customer it would agree to sell a specified amount of power for a quoted price (as quoted by a wholesale market provider) in exchange for the promise that the customer would not use the power during the specified period. Such a transaction could be confirmed using a signed fax, a recorded phone line or an online device.

2. The utility (which actually controls or has title to the released power) would either sell the power to the identified wholesale provider or it would have the option to sell it to another entity for a higher price. Typically, the utility would already have a contractual relationship with the wholesale provider identified by the end-user.

3. The utility would receive cash from the wholesale market buyer and would transfer that cash to the customer using the normal billing procedures. The utility tariff would have to address how payment default risk is handled in the event the wholesale buyer fails to pay.
4. The utility tariff would include a provision for liquidated damages tied to a wholesale reference price for failure of the customer to perform. An additional penalty for failing to reduce load may also be appropriate.

4. <u>The Role for Federal Legislation:</u>

- Implementation of an effective demand buy-down program raises difficult issues

about the appropriate role of the federal government in matters that have been traditionally handled by the States. Moreover, it is clear that the States have the legal authority to mandate implementation of a demand reduction program but for various reasons, have failed to do so. Therefore, given the western state power crises, it is appropriate for the federal government to use its authority to mandate that demand reduction programs to be implemented be implemented by state regulated utilities.

- The draft Barton Bill to provide for electrical emergencies (the Barton Bill) contains provisions that would compel action by entities that are not subject to the jurisdiction of the Federal government. For example, section 103 directs retail energy suppliers to make net metering service available to retail customers. In addition, section 105 requires utility distribution companies to interconnect distributed generation plants to its local distribution facilities. Including a provision mandating that state regulated utilities cooperate in the development and implementation of demand reduction programs is less onerous than the proposals set out in sections 103 and 105.

- The Barton bill should include provisions that compel adoption of demand reduction programs by utility distribution companies. The following provisions should be included in the legislation:

    1. All federal facilities including defense facilities located in the WSCC shall have the right to participate in net metering programs and demand buy-down programs. Retail electric suppliers and utility distribution companies shall implement these programs.

    2. All customers within the WSCC with the ability to reduce consumption by 1 MW or more shall be eligible to participate in demand reduction programs implemented by retail electric suppliers and/or utility distribution companies.

    3. The price paid to end-users for the agreement to reduce consumption shall be deemed to be just and reasonable by the FERC.

- A revised version of the legislative text in the Barton Bill is attached.

#11
LNG TALKING POINTS AND PROJECT DESCRIPTION

LNG

- National energy policy should encourage investment in infrastructure for natural gas and power. Current gas prices in the US make LNG imports financially more attractive.

- Enron is making a significant investment in the global LNG business and much of this investment will be made in the US and South America.

- Enron, with PDVSA as its partner, has been developing an LNG project in Venezuela for the export of LNG to the U.S. market. However, the project has been delayed by the Venezuelan Government which has refrained from providing us with the gas export license without providing reasons for their action. We understand that Secretary Powell has a bilateral with the Venezuelan foreign minister in Quebec later this month and we have asked that he encourage the Venezuelan Government to support the project.

- If the Venezuelan project is approved, enough gas to produce 3000 MW of electricity will be available in the Southeastern US by the end of 2004.

- The Venezuelan LNG project represents an investment of $800 million, $700 million of which will benefit US companies.

#12
TALKING POINTS ON STEEL

DISCUSSION POINTS FOR LAY / CHENEY MEETING

- In August 2000, Enron's Steel Group began trading steel as a commodity, as well as offering customized risk management and financial products for steel producers and end-users. EnronOnline currently offers market participants the real-time transaction tools and information to create a transparent marketplace for steel products.

- We understand that the Administration is reviewing its options with respect to the steel industry, including the possibility of requesting the U.S. International Trade Commission to undertake a Section 201 investigation on imports of certain types of carbon flat-rolled steel products.

- Enron opposes proposals -- like Section 201 -- that seek to restrict the free flow of fairly traded goods.

- Consuming industries are found in every state of the Union and employ 50 Americans for every one steelworker.

- If restrictions are put in place under Section 201, they may have the effect of shutting new competitors out of the steel market.

- Protectionism is bad public policy for other reasons:
  - It sends the wrong signals to other countries - at a critical time in trade negotiations with China, Russia and other trading partners.
  - It protects a handful of companies at the expense of many other US-based, steel consuming companies.
  - It will increase prices to household consumers just as they are seeking to adjust to a slowing economy.

- U.S. consumers have been supporting the U.S. steel industry for more than 30 years, despite its continued inefficiencies. Rather than give the U.S. steel industry further protection, we should be looking for ways to improve the competitiveness of the U.S. steel industry.

- Enron has seen successful transformations in other markets, such as in natural gas and electricity. We believe that changes can be made to the U.S. steel industry to rationalize and increase efficiencies in the industry without harming consumers.

- The government should provide assistance directly -- not at the expense of other industries and consumers

- **[Ken: If it looks like the government feels compelled to protect the domestic steel industry through a 201 proceeding, we should make the point that, in return, the government should insist that the domestic industry establish and institute a comprehensive restructuring plan worthy of the government's support.]**

IMPORTS
SECTION 201: "ESCAPE CLAUSE"
19 U.S.C. § 2251-2253

Purpose: Section 201 of the Trade Act of 1974, as amended, gives the President the authority to provide temporary relief from import competition to a domestic industry that has been seriously injured by increased imports.

Process: A section 201 investigation may be initiated by the filing of a petition by an entity representative of an industry, (including a trade association, firm, union or group of workers), or by a request from the Senate Finance Committee, the House Ways & Means Committee, or the President, or on the U. S. International Trade Commission's ("ITC's") own initiative. The petition must include a statement setting forth the specific purpose for which relief is being sought. The ITC will typically complete its investigation within 120 days from the filing of the petition, or the receipt of the request, although it may extend the deadline to 150 days if the investigation is extraordinarily complicated.

Standard: The ITC conducts its investigation to determine whether an article is being imported in such increased quantities as to be a substantial cause of serious injury, or threat, to the domestic industry producing a similar or competitive product. "Substantial cause" means a cause which is important and not less than any other cause. A public hearing is required during the course of the ITC's investigation.

In considering the question of injury to the domestic industry, the ITC must consider 1) the significant idling of domestic production capacity; 2) the inability of a significant number of domestic firms to operate at a reasonable profit margin; and 3) significant unemployment or underemployment in the domestic industry. In considering whether the imports pose a threat to the domestic industry, the ITC will consider 1) any decline in sales or market share, increasing levels of inventory, declining production, profits, wages or employment; 2) the inability of domestic firms to generate adequate capital to modernize or to maintain existing levels of research and development expenditures; and 3) whether the imports are diverted to the United States due to trade restraints in third countries.

Remedy: If the Commission determines that there is serious injury or threat of serious injury, it will recommend a remedy to the President. That remedy can comprise the imposition of, or an increase in, the duty rate, a tariff rate quota, the modification or imposition of any quantitative restriction, assistance to the domestic industry, or any combination of the above. This recommendation is transmitted to the President, who can reject it, adopt it, or modify it by increasing or decreasing the severity of the proposed relief.

#13
CARBON DIOXIDE

Linking Markets and Technology with Energy and the Environment

Markets

- Competitive, restructured markets are still the best way to provide secure, affordable energy.
- Supply problems such as the current situation in the Western U.S. result primarily from limitations on full market operation or artificial constraints on energy supply and infrastructure development (i.e., government/regulatory constraints).
  - — The value of competitive markets is clear in the deregulated natural gas industry. Higher demand/prices have resulted in an increase in total (oil and gas) U.S. drilling rigs from 775 to 1,120 (40%) from January 2000 to January 2001. Despite the long lag time required to increase gas production, estimated gas production is up by 1 Bcfd from 4th quarter 1999 to 4th quarter 2000.

Energy Supply

- The U.S. should pursue all available energy resources and develop a diverse energy portfolio.
- The U.S. has abundant coal supplies.
  - — Current gas prices are reviving interest in new coal generation but coal prices are up too.
  - — Coal plants have a high hurdle to meet environmental requirements and gain public acceptance.
  - — New coal technologies will help address these issues.
- For the near future, gas will continue to be most important source of new electric generation:
  - — Lowest capital cost.
  - — Quickest to construct and start up.
  - — Lowest emissions, greatest acceptance by the public.
  - — Highest efficiency.
- We need to ensure that gas supply and infrastructure keeps pace with growing demand for gas for power generation, industrial and residential/commercial use.
- Recent report to the Secretary of Energy by the National Petroleum Council highlights the need to focus on access to sources of natural gas, development of gas

delivery infrastructure and appropriate lead times for both.

— North American gas supply is adequate for currently foreseen demand. However, resource development and delivery infrastructure need to keep pace with the demand.

— LNG is a viable option for gas supply and needs to be pursued. LNG technology has blossomed in other parts of the world since its last development in the U.S. It should be part of a diversified energy supply portfolio.

— Example issue: Current high electricity prices in California are in large part related to high cost of natural gas. Gas prices in California are higher than in other states due to constraints on the gas delivery system *inside the state.* Expanding gas delivery capacity in the state would reduce gas prices and help bring down electricity prices.

Regulation

- In the longer term, U.S. energy and environmental policy should present a level playing field with a simplified regulatory approach that allows the energy industry to develop a diverse portfolio of energy sources. One example is **"multipollutant" regulation for the power generation industry**. Such a program should:

  — Expedite new power development by simplifying permitting and regulation.

  — Keep the environment whole.

  — Treat all generators the same regardless of age, fuel, etc.

  — Promote new generating technology for all fuels.

  — *Enron is participating in the development of such an approach that is currently being proposed, and has met with a number of White House, EPA, and DOE officials to present innovative ideas that the Administration could adopt.*

- One major concern is that restructured environmental regulations not be limited to supporting old plants at the expense of new plants (regardless of fuel). New regulations need to provide flexibility for both and old plants while meeting environmental requirements.

Committee on Governmental Affairs
EXHIBIT #A-83

DEPARTMENT OF THE TREASURY
WASHINGTON

April 22, 2002

Senator Joseph I. Lieberman
Chairman, Committee on Governmental Affairs
United States Senate
Washington, D.C. 20510-6250

Dear Mr. Chairman:

On behalf of Secretary O'Neill, I am responding to your letter of March 27, 2002, requesting information about meetings or other communications between Enron and Treasury since January 20, 2001 relating to the May 2001 *Report of the National Energy Policy Development Group (Report)*.

There were no meetings or other communications between Enron and Treasury concerning the *Report*. However, I list below one meeting (and associated communications) requested by Enron to discuss the West Coast energy crisis.

- On March 14, 2001, the Treasury scheduling office received the enclosed fax from Enron requesting a meeting between Secretary O'Neill and Jeffrey Skilling to discuss West Coast energy crisis issues. The scheduling office made arrangements for a 5 p.m. meeting on April 5 and telephoned Enron's Federal Government Affairs office to confirm the date and time.

- On April 5, 2001, Secretary O'Neill, Deputy Secretary Kenneth Dam, General Counsel David Aufhauser, and Chief of Staff Tim Adams met at the Department with Mr. Skilling.

- On April 9, 2001, Mr. Skilling sent the enclosed letter to the Secretary thanking him for the meeting.

Sincerely,

John Duncan
Assistant Secretary for Legislative Affairs

Enclosures

2001-SE-002686

ENRON, WASHINGTON
1775 EYE STREET, NW
Suite 800
Washington, DC 20006
202-466-9145
202-828-3372 (fax)

FAX COVER SHEET

DATE: 3/14/01 4:47 PM
NAME: fax number:
TO:

Attention: Nancy (Scheduler)
The Honorable Paul H. O'Neill
Secretary of Treasury
U.S. Department of Treasury
1500 Pennsylvania Avenue, NW
Room 3330
Washington, DC 20220
202-622-1100
202-622-0073 (fax)

FROM: Linda Robertson, Vice President, Federal Government Affairs
Lora Sullivan PHONE: 202-466-9142
FAX: 202-828-3372

Number of pages: 1

Re: Request for a meeting with the Secretary on April 5 in the afternoon

Dear Nancy:

Jeff Skilling, President and CEO for Enron would like to schedule a meeting with the Secretary to discuss West Coast energy crisis issues. We would like to schedule a short meeting sometime after Noon on Thursday, April 5, 2001. If this is possible, please call me at the number listed below.

Thank you for your assistance in this regard.

Lora Sullivan
Federal Government Affairs Representative
202-466-9142

00100000000380

2001-SE-003680

Jeffrey K. Skilling
President & Chief Executive Officer

Enron Corp.
1400 Smith Street
Houston, TX 77002
713-853-6894

P.O. Box 1188
Houston, TX 77251-1188
Fax 713-646-8381
jeff.skilling@enron.com

April 9, 2001

The Honorable Paul H. O'Neill
Secretary of Treasury
U.S. Department of Treasury
1500 Pennsylvania Avenue, NW
Room 3330
Washington, DC 20220

Dear Secretary O'Neill:

I appreciated the opportunity to visit and to talk to you about the West Coast energy markets. As this debate continues to unfold, we stand ready to be a resource to you whether it is policy analysis, economic research or historical industry information.

I look forward to seeing you soon.

Best personal regards.

Sincerely,

Endless possibilities.™

00100000000382

Committee on Governmental Affairs
EXHIBIT #A-84

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

San Diego Gas & Electric Company,
Complainant,

v. Docket No. EL00-95-031

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

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

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

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

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

(Issued June 19, 2001)

Introduction and Summary

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(continued...)

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

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

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

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

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

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

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

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

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

I. Background

In an order issued August 23, 2000, [15] the Commission instituted formal hearing proceedings under section 206 of the FPA to investigate the justness and reasonableness of the rates for energy and ancillary services of public utility sellers into the ISO and PX spot markets, and also to investigate whether the tariffs, contracts, institutional structures, and bylaws of the ISO and PX were adversely affecting the wholesale power markets in California. These proceedings were intended to investigate the significant increases in the prices for energy and ancillary services in the California market.

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

As an interim measure, the Commission also established a $150/MWh breakpoint under which public utility sellers bidding above the breakpoint receive their actual bids, but are subject to monitoring and reporting requirements to ensure that rates remain just and reasonable, including the potential for

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

having to pay refunds for prices charged above the breakpoint. [16] The December 15 Order also required the development of a longer term mitigation plan to replace the interim breakpoint methodology by May 1, 2001.

On January 23, 2001, the Director of the Division of Energy Markets in the Office of Markets, Tariffs and Rates convened a technical conference to develop a plan to replace the interim breakpoint price. [17] Comments and reply comments on how to replace the interim break-point were filed with the Commission. In March 2001, Commission Staff issued a recommendation for prospective market monitoring and mitigation for the real-time electric market, and comments were filed on this proposal. The comments focused in particular on the method used for price mitigation and the periods when mitigation would be applied.

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

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

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

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

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

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

It established a mechanism for price mitigation for all sellers (excluding out-of-state generators) bidding into the ISO's real-time market during a reserve deficiency, beginning at a Stage 1 alert, which is defined as having reserves of 7 percent or less. Under this mechanism, the

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

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

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

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

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

II. Discussion

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

A. Outage Coordination

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

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

The ISO has the authority to coordinate and control generation outage schedules for resources under PGAs. The Commission clarifies that only the ISO's outage coordination role will be extended to all other in-state generating facilities insofar as these generators must submit to the ISO maintenance

schedules for their generating units. This will provide the ISO with the information necessary to maximize the efficient use of all in-state resources. For example, with this information, the ISO will be able to determine whether to schedule generation under its control based on when other generation resources will be out-of-service. The ISO, however, will not be authorized to schedule maintenance for units not under a PGA.

B. Selling Obligations

The mitigation plan requires those generators with PGAs, as well as non-public utility generators in California selling through the ISO markets or using the ISO's transmission lines, to offer the ISO all of their capacity in real time during all hours if it is available and not already scheduled to run. This must-offer obligation does not apply to power scheduled to run under bilateral agreements. The must-offer obligation does not apply to hydroelectric power because of its multi-purpose limitations (e.g., irrigation, recreation, and power production). The must-offer obligation is designed to prevent withholding and thereby to ensure that the ISO will be able to call upon available resources in the real-time market to the extent that energy is needed. The basis for this requirement is that, under competitive conditions, a generator that has available energy in real time should be willing to sell that energy at a price that covers its marginal costs, since it has no alternative purchaser at that time. The rehearing requests raise a number of issues that will be addressed below.

1. Applicability to Non-Public Utility Generators

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

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

The Commission denies the requests for rehearing. The Commission is not asserting jurisdiction over non-public utilities. Rather, as the Commission explained in the April 26 Order, it is exercising its conditioning authority to assure that all generators located in California, including non-public utility generators, that voluntarily sell into the ISO's spot market or that use the ISO's interstate transmission

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

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

2. Extent of the Must-Offer Obligation

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

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

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

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

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

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

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

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

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

[24]See Rehearing Request by Reliant.

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

[26]Rehearing requests by NCPA, NRECA.

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

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

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

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

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

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

3. Withholding Generation for Operational Reasons

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

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

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

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

4. Other Issues

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

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

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

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

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

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

C. Demand Response

The April 26 Order provided that beginning on June 1, 2001, each public utility purchasing electricity in the ISO's real-time market is required to submit demand-side bids that will indicate the price at which load will be curtailed and will identify the load to be curtailed.

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

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

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[30] See Rehearing Request by CMUA,

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

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

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

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

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

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

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

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

D. Price Mitigation for California and the WSCC

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

Many rehearing requests, as well as comments in the West-Wide proceeding, contend the Commission should have extended mitigation to cover all hours. They contend that evidence from a number of studies shows that sellers have been able to exercise market power during all hours. They contend that the Commission has the obligation under the FPA to assure just and reasonable rates in all

hours.[35] Duke Energy and other generators insist that the record does not show that market power has been exercised.

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

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

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

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

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

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

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

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

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

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

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

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

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

[40] CPUC Request for Rehearing at 7.

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

[42] CEOB Request for Rehearing at 4.

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

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

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

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

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

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

On April 26, 2001, the Commission adopted a prospective monitoring and mitigation plan for real-time California wholesale electric markets which replaced that previously in effect. The Commission's plan: (1) enhanced the ISO's ability to coordinate and control planned outages; (2) required sellers with PGAs, as well as non-public utility generators located in California that voluntarily make sales through the ISO's markets or use the ISO's interstate transmission grid (with the exception of hydroelectric power), to offer all their available power in real time during all hours; (3) required public utility load serving entities to submit demand bids (identifying the price at which load will be curtailed) in the real-time market during all hours; (4) established conditions, including refund liability, on public utility sellers' market-based rate authority to prevent anticompetitive bidding behavior in the real-time market during all hours; (5) required the ISO to submit weekly reports on schedule, outage, and bid data for all hours so that Commission staff can continue to monitor generating unit outages and real-time prices; (6) established a mechanism for price mitigation for all sellers (excluding out-of-state generators) bidding into the ISO's real-time market during a reserve deficiency, beginning at a Stage 1 alert (i.e., when reserves are below 7 percent). This mechanism provided a formula (based on gas-fired generation) for the ISO to use to establish the real-time market clearing price when mitigation applies. Higher bids were permitted if they could be justified.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

E. ISO Market Clearing Auction During Periods of Reserve Deficiency

Under the April 26, 2001 mitigation plan, each gas-fired generator in California (both those signing PGAs and covered non-public utility gas-fired generators) will file with the Commission and the ISO (on a confidential basis) the heat rate and emission rate for each generating unit. The ISO would use these heat rates to calculate a marginal cost for each generator by using a proxy for the gas costs, emission cost, and a $2.00/MWh adder for O&M expenses. The gas cost proxy was based on an average of the daily prices published in Gas Daily for all California delivery points. The emission cost was to be calculated by the ISO using emissions costs from Cantor Fitzgerald Environmental Brokerage Services and the emissions rate for the unit. All generators would be paid a single market clearing price reflecting the last unit dispatched calculated using the proxy prices.

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

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

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

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

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

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

2. Calculation of Market Clearing Price

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

a. Gas Costs

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

b. Emission Costs

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

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

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

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

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

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

[67]Rehearing Request by Williams.

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

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

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

c. O&M Adder

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

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

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

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

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

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

d. Heat Rate

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

F. Conditions on Market-Based Rate Authority

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

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

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

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[76](...continued)
Edison.

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

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

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

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

G. Refunds

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

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

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

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

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

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

H. Underscheduling Penalty

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

I. Confidentiality of Data

The Commission stated in the April 26 Order that it would continue the previous practice of keeping bid data confidential for six months, because disclosure of such information may lead to a reduction in competition because it will allow competitors to learn what their competitors are bidding and could lead to price collusion or coordination. The Commission also found that generator's heat rates and emission cost information was also confidential business information that should not be disclosed.

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

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

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

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

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

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

J. Review and Duration of the Mitigation Plan

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

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

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

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

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

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

K. RTO Proposal

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

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

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

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

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

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

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

L. West-Wide 206 Implementation

In the April 26 Order, the Commission instituted an investigation under section 206 of the FPA into the rates, terms and conditions of sales for resale of electric energy in interstate commerce in the WSCC other than sales through the ISO's markets, to the extent that such sales for resale involve: (1) electric energy sold in real-time spot markets (i.e., up to 24 hours in advance) and (2) take place during conditions when contingency reserves (as defined by the WSCC) for any control area fall below 7 percent. These proceedings were instituted to investigate whether and the extent to which significant increases in the prices for energy and ancillary services in the California market are affecting prices for such services in the WSCC outside of California.

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

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

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

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

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

1. WSCC Mitigation Plan Overview

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

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[87] 95 FERC ¶ 61,115, at 61,356.

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

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

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

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

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

2. Interventions and Comments

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

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

3. Megawatt Laundering

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

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

4. The Proposed 7 Percent Reserve Deficiency Trigger

The April 26 Order established a mechanism for price mitigation for all sellers (excluding out-of-state generators) bidding into the ISO's real-time market during a reserve deficiency, and proposed that mitigation in the WSCC would be triggered when contingency reserves (as defined by the WSCC) for any control area fall below 7 percent.

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

5. The Proposed Must-Offer Requirement

In the April 26 Order, the Commission included a requirement that all generators in California (with the exception of hydroelectric power), including non-public utility generators that make sales through the ISO's markets or that use the ISO's interstate transmission grid, must offer any power that

they have available in real time to the ISO. This includes power not already scheduled to run through bilateral agreements.[88] With respect to the WSCC investigation, the Commission stated that it intends to mirror the approach used in California.

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

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

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

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

6. Applicability to Non-public Utilities

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

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[88] 95 FERC ¶ 61,115, at 61,355-57.

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

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

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

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

7. Refund Issues

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

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[89] Id. at 61,356 .

[90] Id. at 61,365.

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

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

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

8. Mitigation Beyond Summer 2001

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

M. Settlement Conference

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

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

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

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

N. ISO Compliance Filing

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

The Commission orders:

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

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

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

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

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

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

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

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

(SEAL) Commissioner Breathitt concurred with a separate statement attached.

Linwood A. Watson, Jr.,
Acting Secretary.

Linwood A. Watson, Jr.,
Acting Secretary.

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

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

[94]Request for stay.

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

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

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

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

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

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company
Complainant,

v. Docket No. EL00-95-031

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

Investigation of Practices of the California Independent System Operator and the California Power Exchange — Docket No. EL00-98-030, EL00-98-033

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

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

(Issued June 19, 2001)

MASSEY, Commissioner, concurring in part:

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

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

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

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

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

What is curious about this aspect of the order is that the concern is to avoid discouraging new supply. However, as the well respected economist Alfred Kahn recently said of our long reliance on cost of service regulation, "(i)f the literature agrees on anything about that experience, it is that cost-based regulation, as traditionally practiced, has encouraged the goldplating of service and the very excess capacity that seemed to promise such enormous benefits to consumers during the past decade if

rates were deregulated."[1] Dr. Kahn believes that cost of service may lead to too much supply. Thus, I do not understand the majority's logic concerning cost-based regulation and supply adequacy.

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

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

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

William L. Massey
Commissioner

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company,

v. Docket No. EL00-95-031

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

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

Investigation of Practices of the California Independent System Operator and the California Power Exchange	Docket Nos. EL00-98-030 EL00-98-033
California Independent System Operator Corporation	Docket Nos. RT01-85-000 RT01-85-001
Investigation of Wholesale Rates of Public Utility Sellers of Energy and Ancillary Services in the Western Systems Coordinating Council	Docket Nos. EL01-68-000 EL01-68-001

(Issued June 19, 2001)

Breathitt, Commissioner, concurring;

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

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

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

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

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

Linda K. Breathitt
Commissioner

Committee on Governmental Affairs
EXHIBIT #A-85

Elsewhere in
Press Rel
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FOTT 2001
NBP 2001
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Press Release

Enron Reiterates Confidence In Operations and Earnings Outlook

FOR IMMEDIATE RELEASE: Tuesday, June 19, 2001

HOUSTON -- Enron reiterated today strong confidence in its earnings outlook.

"Our business continues to be extremely strong. Interest in our energy delivery and energy management capabilities has never been higher," said Jeffrey K. Skilling, Enron president and CEO. "Having reviewed the recent FERC action on price controls in the western U.S., we remain very confident that we will meet the market's consensus recurring earnings estimates of $0.42 and $1.79 per share, respectively, for both the second quarter and full year 2001."

"We're hopeful this action allows FERC to now concentrate on the vitally important task of opening the nation's electricity grid so that power can move from where it's plentiful to where it's needed," Skilling said.

Enron is one of the world's leading electricity, natural gas and communications companies. The company, with revenues of $101 billion in 2000, markets electricity and natural gas, delivers physical commodities and financial and risk management services to customers around the world, and has developed an intelligent network platform to facilitate online business. Fortune magazine has named Enron "America's Most Innovative Company" for six consecutive years. Enron's Internet address is www.enron.com. The stock is traded under the ticker symbol "ENE."

This press release includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Although Enron believes that its expectations are based on reasonable assumptions, it can give no assurance that its goals will be achieved. Important factors that could cause actual results to differ materially from those in the forward looking statements herein include success in marketing natural gas and power to wholesale customers; the ability to penetrate new retail natural gas and electricity markets, including the energy outsource market, in the United States and Europe; development of Enron's broadband network and customer demand for intermediation and content services; and conditions of the capital markets and equity markets during the periods covered by the forward looking statements.

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United States General Accounting Office

GAO

Report to Congressional Requesters

Committee on Governmental Affairs
EXHIBIT #A-86

June 2002

ENERGY MARKETS

Concerted Actions Needed by FERC to Confront Challenges That Impede Effective Oversight

GAO
Accountability * Integrity * Reliability

GAO-02-656

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Abbreviations

AFMC	Air Force Materiel Command
EPACT	Energy Policy Act
ERCOT	Electric Reliability Council of Texas
EWG	exempt wholesale generator
FERC	Federal Energy Regulatory Commission
ICE	Intercontinental Exchange
IRS	Internal Revenue Service
ISO	independent system operator
MMU	market monitoring unit
MOR	Market Observation Resource
NYMEX	New York Mercantile Exchange
OASIS	Open Access Same-Time Information System
OMB	Office of Management and Budget
OMTR	Office of Markets, Tariffs, and Rates
OPM	Office of Personnel Management
PJM	Pennsylvania, New Jersey, Maryland
PUHCA	Public Utility Holding Company Act
PURPA	Public Utilities Regulatory Policies Act
QF	qualifying facility
RTO	regional transmission organization

United States General Accounting Office
Washington, DC 20548

June 14, 2002

The Honorable Joseph I. Lieberman
Chairman, Committee on Governmental Affairs
United States Senate

The Honorable Jean Carnahan
United States Senate

As requested, we are reporting on the Federal Energy Regulatory Commission's (FERC) efforts to revise its approach to regulating and overseeing the nation's natural gas and electric power industries in light of these industries' evolution from highly regulated monopolies to competitive energy markets. This report contains recommendations to the Chairman of FERC on developing and implementing an effective regulatory and oversight approach for these markets. The report also contains a matter for congressional consideration on the need to review FERC's legal authorities to determine whether revisions are warranted in view of the change to competitive energy markets.

As agreed with your offices, unless you publicly announce its contents earlier, we plan no further distribution of this report until 30 days from the date of this letter. We will then send copies to other appropriate congressional committees; the Chairman, FERC; and the Director, Office of Management and Budget. We will also make copies available to others upon request. In addition, the report will be available at no charge on the GAO web site at http://www.gao.gov.

If you or your staff have any questions concerning this report, please call me at (202) 512-3841. Key contributors to this report are listed in appendix IV.

Jim Wells

Jim Wells
Director, Natural Resources
and Environment

Executive Summary

Purpose

Consumers in various parts of the United States have experienced substantial fluctuations in the prices they pay for natural gas and electricity as these industries make the transition from regulated monopolies to competitive markets. These fluctuations—the most notable in California during the summer of 2000—have caused some consumers and state officials to question the wisdom of moving to competitive energy markets. They have also raised concerns about the ability of the federal government to adequately regulate and oversee these new markets. The responsibility for ensuring that wholesale prices for natural gas and electricity, sold and transported in interstate commerce, are "just and reasonable," generally rests with the Federal Energy Regulatory Commission (FERC).

The Chairman of the Senate Committee on Governmental Affairs and Senator Carnahan asked GAO to determine (1) how FERC has revised its regulatory and oversight approach in response to the new energy markets and (2) what management challenges FERC faces in effectively regulating and overseeing these markets. To respond to the request, GAO reviewed relevant legislation, regulations, studies, and documents pertaining to FERC's regulation and oversight of these industries. GAO also interviewed a wide range of current and former FERC Chairmen, Commissioners, and officials. In addition, GAO surveyed FERC staff in the Office of Markets, Tariffs and Rates and related sections of the Office of the General Counsel who have primary responsibility for regulating the natural gas and electricity industries. About 71 percent, or 271, of these 384 staff responded to GAO's survey. Furthermore, GAO obtained information from a wide range of FERC's stakeholders—including state and industry representatives—and other industry experts. For example, GAO surveyed the chairmen of the state public utility commissions or boards. Thirty of the 49 commissions or boards responded to GAO's survey. (See ch. 1 for GAO's detailed scope and methodology and app. II for a copy of the FERC employee survey with the quantitative results.)

Background

FERC was established in 1977 as a successor to the Federal Power Commission. FERC is an independent federal agency of about 1,200 employees. Five Commissioners, each appointed by the President to a 5-year term, and confirmed by the Senate, lead the agency. The President designates one of the Commissioners as the Chairman, who is responsible for the agency's administrative operations. In addition to regulating and overseeing interstate transportation and wholesale sales of natural gas and electricity, FERC regulates transmission of oil by pipelines, licenses hydroelectric projects, and approves site choices for interstate pipelines

and related facilities. Jurisdiction over other aspects of the natural gas and electric industries, such as retail sales, construction of electric power plants and transmission lines, and intrastate transportation, belongs to state and local governments.

For nearly a century, the natural gas and electricity industries were regulated as natural monopolies and dominated by a relatively few, large public utilities that produced, transported, and sold natural gas and electricity to the ultimate users.[1] This monopoly structure controlled the entry, prices, and profits of industry participants. With technological, economic, and policy developments over the past 25 years, these industries have undergone a transition from this highly regulated environment to one that places greater reliance on competition to determine entry, prices, and profits. Natural gas was first to make the shift, facilitated by passage of the Natural Gas Policy Act of 1978 and subsequent FERC orders in 1985 and 1992 that opened pipeline transportation to all on equal terms and required pipeline companies to completely separate or "unbundle" their transportation, storage, and sales services. As a result, natural gas became a commodity bought and sold separately from its transportation.

The electricity industry has experienced similar developments, starting about the same time but evolving more slowly than the natural gas industry. The Public Utility Regulatory Policies Act in 1978 introduced competition by requiring electric utilities to buy electricity produced by nonutility, electric power generators. Then in 1992, the Congress passed the Energy Policy Act, authorizing FERC to require utilities, on a case-by-case basis, to allow competitors to use their transmission lines for wholesale sales of electricity. In 1996, FERC ordered that electric transmission systems be opened to all qualified wholesale buyers and sellers of electric energy. FERC also required utilities to "functionally unbundle" their generation and transmission businesses to prevent discriminatory practices, such as not allowing competitors equal access to transmission lines. One option FERC provided the utilities to help them achieve unbundling was to transfer management of their transmission lines to an independent system operator that would manage the system without any special interests and for all users' benefit. In 1999, FERC

[1] A natural monopoly is a company that becomes the only supplier of a product or service because the nature of that product or service makes a single supplier more efficient than competing ones.

issued an order asking all utilities to transfer control of their transmission lines to regional transmission organizations. FERC is in the process of establishing these organizations to cover the continental United States.

Under the traditional regulatory framework, FERC established individual utilities' terms, conditions, and rates for transportation and wholesale sale of natural gas and electricity in interstate commerce. To ensure that the rates these utilities charged were just and reasonable, FERC based the rates on the utilities' cost to provide the service plus a fair return on investment, which is generally referred to as cost-of-service regulation. With the opening of pipelines and transmission lines, other energy producers and marketers began to compete with the traditional utilities to the point that a complex structure of formal and informal primary and secondary energy markets has evolved. As competition has increased, FERC has allowed more and more producers and marketers to sell their energy at prices determined in the marketplace.

Results in Brief

FERC has not yet adequately revised its regulatory and oversight approach to respond to the transition to competitive energy markets. The agency recognizes that the change from highly regulated monopolies to competitive markets requires it to fundamentally change how it does business. However, it has struggled through various strategic planning and other efforts to define the specific strategies, processes, and activities that it will use to regulate and oversee these markets. Specifically, GAO found the following:

- An ambitious, 2-year reengineering effort begun in 1997 was intended to position the agency to operate within the new market realities, but the effort achieved little more than superficial changes to FERC's organizational structure.
- To date, FERC's initiatives to monitor competitive markets have served more to help educate FERC's staff about the new markets than produce effective oversight efforts. For example, the agency's Market Observation Resource room makes a substantial amount of market data available to staff in a readily usable format; however, this information has not yet been used to initiate an enforcement action or to confirm or refute a problem identified elsewhere in the agency.
- FERC's difficulties with developing an effective approach for monitoring competitive markets are compounded by the need to continue to carry out

its traditional cost-of-service regulation as the industry makes the transition to competitive markets.

- FERC is attempting to develop an approach for competitive markets using legal authorities that were enacted primarily when the energy industries were regulated monopolies. For example, FERC generally does not have the authority to levy meaningful civil penalties. While this authority may not have been necessary for cost-of-service regulation, it is important if FERC is to pose a credible threat and deter anticompetitive behavior or violations of market rules by market participants.

Absent an effective regulatory and oversight approach, FERC lacks assurance that today's energy markets are producing interstate wholesale natural gas and electricity prices that are just and reasonable. Although many details remain to be decided, FERC's current thinking is that the regional transmission organizations will be required to establish independent units to serve as the agency's frontline monitors for the new markets. However, it is likely to be several years before these units will be fully operational. Therefore, GAO is making recommendations to the Chairman, FERC, aimed at improving the interim regulation and oversight of these markets until a long-term, comprehensive approach can be established. In addition, GAO is suggesting that the Congress may want to review and revise FERC's authorities in the context of competitive market structures, such as the need to levy meaningful civil monetary penalties.

Under any future scenario, FERC must overcome significant human capital and organizational structure challenges to effectively regulate and oversee the evolving energy marketplace. Although its staff will continue to do some cost-of-service regulation, FERC needs more staff knowledgeable about competitive energy markets and skilled in regulating and overseeing them. FERC is taking steps to transform its workforce so that it will be able to successfully regulate in a competitive market environment. However, GAO found that FERC

- has had difficulty recruiting such staff, in large part, because it has trouble competing with private sector salaries;

- faces the impending retirement of a large portion of its staff—over one-quarter of its employees will be eligible to retire by 2005;

- has used recruitment bonuses, retention allowances, tuition reimbursement, and flexible work schedules to attract new staff and to retain current employees, but it has not taken advantage of the full range

of personnel flexibilities and tools available to federal agencies, such as special salary rates; and

- has not developed a strategic human capital management plan to assess its specific workforce needs and to develop strategies to address them.

Furthermore, FERC's current organizational structure diffuses its market oversight function, making it more difficult to provide the communication, focus, and management attention needed to successfully implement a new regulatory and oversight approach. FERC plans to establish an Office of Market Oversight and Investigation reporting to the Chairman to provide this communication, focus, and management attention, although many details are yet to be resolved. GAO is making recommendations to the Chairman, FERC, to help address the agency's serious human capital concerns.

In commenting on a draft of this report, FERC agreed with GAO's conclusions that the agency has not done all that it could to oversee energy markets and with the report's recommendations to improve market oversight and to address the human capital challenges faced by FERC. The agency also provided technical comments that GAO incorporated as appropriate.

Principal Findings

FERC Has Not Yet Defined and Implemented an Effective Regulatory and Oversight Approach for Competitive Energy Markets

As competitive energy markets started to develop in the early 1990s, FERC recognized that it would need a new approach to ensure just and reasonable energy prices. Its first strategic plan, which was completed in September 1997, confirmed the need for this new approach but did not delineate the strategies needed to put such an approach into place. Instead FERC, in 1997, launched a 2-year, $20-million project to reengineer itself to operate in this competitive-market environment. One of the more significant results of this project, which is referred to as FERC First, was to combine the agency's staff responsible for natural gas and electricity regulation into a new Office of Markets, Tariffs and Rates. This new office was to be responsible for regulating and overseeing competitive energy markets. FERC First, however, did not bring about the fundamental changes that were anticipated and needed to implement a new regulatory approach. For example, 74 percent of the employees responding to GAO's survey believed that FERC First had improved the agency's ability to effectively monitor or regulate energy markets to little or no extent. The

agency has subsequently continued to struggle to define the specific strategies, processes, and activities that it will use to regulate and oversee the emerging energy markets. For example, although FERC made improvements to its strategic plan in 2000 and 2001, the plan still lacks outcome-oriented goals and objectives and important details on how FERC will monitor these markets. The agency has yet to decide what market monitoring means in the context of FERC's responsibility to ensure that energy prices are just and reasonable.

FERC has also tried various efforts to oversee energy markets, including a staff investigation in 2000 of the nation's wholesale electricity markets and the development of a Market Observation Resource room that serves as a central source of market data that FERC staff can view electronically using various software packages. These efforts to date, however, have served more as educational opportunities for FERC staff than as effective oversight tools. For example, in commenting on the staff investigation of wholesale electricity markets, FERC management concluded that the investigation made it clear that the agency did not have enough people who could analyze market information. Similarly, the major products of the Market Observation Resource room have been daily and monthly informational newsletters prepared for FERC's Commissioners and managers on energy market events and conditions, such as business news, natural gas supply levels, electricity price trends, and power plant outages.

Moreover, because FERC's legal authorities for natural gas and electricity are mostly derived from laws enacted when the industries comprised highly regulated monopolies, FERC has been attempting to develop and implement a regulatory and oversight approach for competitive markets, with an outdated legislative framework and using authorities that may not be adequate for today's competitive markets. For example, the potential for a company to engage in anticompetitive behavior and charge excessive prices for electricity is a significant concern when rates are determined by the marketplace instead of cost-of-service regulation, especially when the markets are still evolving. However, FERC's authority to levy civil penalties if it identifies this type of behavior is limited, because its authority is derived from laws that were enacted in a cost-of-service environment. Without a meaningful range of penalties, FERC lacks adequate enforcement "bite" to deter anticompetitive behavior or other violations of market rules. Such deterrence is an important part of an effective oversight approach, especially because FERC will likely not be able to review all the transactions in detail to identify such behavior or violations.

Finally, frequent changes in FERC's leadership have been another contributing factor to FERC's slow progress in developing and implementing a new approach. FERC has had four different Chairs over the past 5 years. As the agency's chief administrator, the Chair sets the agenda and priorities. Making fundamental changes in an agency's operations, such as implementing a new regulatory and oversight approach, can take a sustained effort over several years. This can be difficult to achieve with significant shifts in an agency's agenda and priorities caused by continuous change in its top leadership.

To address these issues, GAO recommends that the Chairman, FERC, take the following actions:

- Update the agency's strategic plan to include outcome measures that can be used to assess how well FERC is doing in achieving its strategic goals and objectives for overseeing competitive energy markets. This plan should also include specific strategies for achieving the goals and objectives that set out explicitly how FERC will work with market participants to provide comprehensive oversight of the markets.

- FERC should examine how the bulk power studies and the data sources currently available through the Market Observation Resource room can be used as effective market monitoring tools in the interim, until a more comprehensive approach for overseeing energy markets is developed.

In addition, GAO is suggesting that the Congress may wish to convene public hearings to review FERC's authorizing legislation and determine, in consultation with FERC Commissioners, whether FERC's authorities need to be revised in light of the changing energy markets. The Congress may also want to consider providing FERC with the appropriate range of authorities to levy civil penalties against market participants that engage in anticompetitive behavior and violate market rules.

FERC Faces Significant Human Capital and Organizational Structure Challenges to Effectively Regulate and Oversee Competitive Energy Markets

FERC does not currently have enough staff with the skills and knowledge of competitive energy markets to effectively regulate and oversee these industries. FERC's employees were mostly recruited and trained for cost-of-service regulation, and the agency has not yet conducted the training and hiring necessary to adapt its workforce to a competitive market environment. FERC has been providing its current staff with increased training opportunities to enhance their knowledge of energy markets. For example, the Office of Markets, Tariffs and Rates doubled its training budget from 2000 to 2001. Despite these efforts, the general feeling among

FERC staff responsible for regulating and overseeing energy markets is that they still need additional, focused training on how energy markets work. Over 80 percent of the staff in the Office of Markets, Tariffs and Rates and the related sections of the Office of the General Counsel who responded to GAO's survey said that they needed more training in market functions and market structures.

Moreover, successfully recruiting staff at the mid- and upper-levels who already have knowledge and experience with competitive markets is critical to FERC's efforts to quickly adapt its workforce. However, FERC has had limited success with hiring these types of employees. According to FERC, the salary differentials between government positions and those in the private sector have made it difficult for the agency to attract highly skilled and knowledgeable professionals away from the private sector. For example, FERC has advertised an "Energy Industry Analyst—(Energy Trader)" position at the GS-15, step 10, level—which currently pays about $120,000—three different times with little success in finding a qualified candidate.

In addition, over one-quarter of FERC's employees will be eligible to retire by 2005, creating an opportunity for FERC to refocus its workforce competencies to those more geared toward regulating and overseeing competitive markets. However, this large-scale retirement will also create a dearth of institutional knowledge, because FERC will continue to perform some traditional cost-of-service regulatory work as the industries transition to competitive markets, and for some time it will continue to need highly qualified and experienced staff to perform these functions.

Nonetheless, FERC has not taken full advantage of the personnel flexibilities and tools available to federal agencies to help it address recruitment and employee retention challenges. Although FERC has used recruitment bonuses, retention allowances, tuition reimbursement, and alternative work schedules, it has not yet used other available tools, such as special pay rates, to help it address its human capital challenges.

FERC's efforts to address its human capital issues have also been hampered by its lack of a strategic human capital management plan. FERC has not yet undertaken a systematic strategic human capital planning process to identify the specific staff competencies it needs and develop the strategies that it will use to meet these needs. For example, FERC has not completed a detailed assessment and plan that will help the agency address its potential loss of leadership continuity, institutional knowledge, and expertise from the impending retirement of many of its employees.

Furthermore, FERC's market oversight function currently is dispersed across various parts of the agency. This organizational structure makes it more difficult for this function to receive the priority and attention that is needed to bring about fundamental change. FERC's recently announced plans to create a new Office of Market Oversight and Investigation, which will focus on analyzing and monitoring energy markets, may address this issue. For example, this new office is expected to report directly to the Chairman, thereby elevating the attention of the market oversight function within the agency. However, many details about the office and how it will carry out its responsibilities have not yet been determined.

To address its serious human capital challenges, GAO is recommending that the Chairman, FERC, in the short term, identify and formally assess the personnel tools, flexibilities, and strategies available to federal agencies to recruit and retain employees. The Chairman should also develop an action plan to identify and target additional training and development opportunities for current staff involved or potentially involved in carrying out FERC's market oversight functions.

In the longer term, GAO recommends that the Chairman, FERC, develop a comprehensive strategic human capital management plan to guide FERC's efforts to recruit, develop, train, and retain staff knowledgeable in regulating competitive markets. The plan should be linked to FERC's strategic and business plans.

Agency Comments

We provided FERC with a draft of this report for review and comment. FERC agreed with GAO's conclusions, noting that its internal restructuring to support its new market oversight role has not kept pace with the speed of the energy industry's restructuring. The agency also commented that GAO's recommendations are consistent with its current direction. FERC said that its recent aggressive measures to address its key challenges are paying off. According to FERC, it has developed preliminary plans on how its new Office of Market Oversight and Investigation will work and the office will be operational in August 2002. FERC also said that it has recently made significant progress in hiring new employees and will explore all of the hiring flexibility available to it as it focuses on the skill sets needed for market oversight and investigation. FERC further said that it is reviewing existing budget allocations across the agency for additional resources and working to craft more focused training programs to build its staff's technical and leadership capabilities. FERC also agreed that its ability to develop, regulate, and oversee competitive energy markets could be enhanced with additional statutory authority, particularly for assessing

civil penalties, and with guidance from the Congress on the agency's appropriate role in these markets.

FERC's written comments are presented in appendix III. The comments contain an attachment summarizing the agency's current efforts to address issues of energy market oversight and human capital, and the need for additional legislative authority. FERC also provided a draft of the mission and function statement and organizational design for its new Office of Market Oversight and Investigation, and a list of the services and products the office is to provide. In addition, FERC provided us with some technical changes, which we incorporated into the report as appropriate.

Chapter 1: Introduction

Consumers in various parts of the United States have recently experienced large fluctuations in energy prices as the natural gas and electric power industries undergo a major restructuring from regulated monopolies to competitive markets. The price spikes and supply disruptions that occurred in California and other parts of the West during 2000 and into 2001 are examples of the complications that have arisen for these industries and government regulatory agencies during this shift from regulated prices based on utilities' cost of providing service to market-based prices. The Federal Energy Regulatory Commission (FERC) has both prompted and reacted to the fundamental changes that the energy industries are undergoing. Established to regulate energy monopolies, FERC first encouraged the restructuring of the natural gas industry and today is doing the same for electricity. The price spikes in California and elsewhere have fueled debate about the wisdom of restructuring these industries and have drawn wider attention than ever before to FERC and its ability to carry out its legislative responsibilities for ensuring that natural gas and electricity prices are just and reasonable. In response to these concerns, the Congress is currently debating comprehensive energy legislation.

FERC Is the Principal Federal Agency Regulating and Overseeing the Natural Gas and Electricity Industries

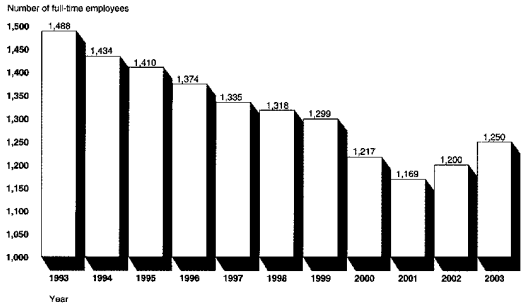
The natural gas and electricity industries perform three primary functions in delivering energy to consumers: (1) producing the basic energy commodity, (2) transporting the commodity through pipelines or over power lines, and (3) distributing the commodity to the final consumer. A range of federal, state, and local entities regulate different aspects of these functions. While generation siting, intrastate transportation, and retail sales are generally regulated by state or local entities, wholesale sales and interstate transportation generally fall under federal regulation, primarily by FERC. Under federal law, FERC is responsible for regulating the terms, conditions, and rates for the interstate transportation and sale for resale of natural gas and electricity. FERC is charged with ensuring that the terms, conditions, and rates are just and reasonable.

FERC was established in 1977 as a successor to the Federal Power Commission and is an independent regulatory agency. In addition to regulating and overseeing the interstate transmission and interstate wholesale sales of natural gas and electricity, FERC regulates the interstate transmission of oil by pipeline; licenses and inspects private, municipal, and state hydroelectric projects; and approves site choices as well as decisions to abandon interstate pipelines and related facilities no longer in use.

FERC's Resources and Organizational Structure

FERC's estimated budget for fiscal year 2002 is about $192 million and provides funding for 1,200 staff years.[1] For fiscal year 2003, FERC has requested a budget of about $200 million and 1,250 staff years. While FERC has requested an increase for fiscal year 2003, its staffing levels have generally decreased over the last decade. For example, the 1,250 staff years requested for next fiscal year are 238 fewer than FERC had in fiscal year 1993 (see fig. 1). According to FERC managers, these staff reductions have occurred while the agency's workload has increased in both volume and complexity. Although the Congress sets FERC's budget, FERC recovers the full cost of operations through annual charges and filing fees assessed on the industries it regulates.

Figure 1: FERC Staff Years, 1993-2003



Note: 1993-2001 staff years are actual figures. The 2002 and 2003 figures are estimates based on the budget requests for those years.

Source: GAO's analysis of FERC budget data.

Five Commissioners, each appointed to a 5-year term by the President, and confirmed by the Senate, lead FERC. The President designates one of the five Commissioners as the Chair, who also serves as the administrative head of the agency and directs its staff. FERC's staff are currently

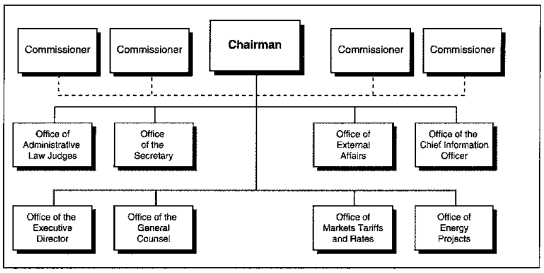
[1] Staff resources are measured in this report in terms of full-time-equivalent staff years.

organized around the agency's two major program or responsibility areas—energy markets and energy projects—with their supporting administrative and management functions. About 35 percent of FERC's staff focus on energy markets. These staff are predominantly located in the Office of Markets, Tariffs and Rates (OMTR) and the Office of the General Counsel. OMTR was created in 1998 to integrate the agency's regulation of the electric, natural gas, and oil pipeline industries. It plays a lead role in monitoring, promoting, and maintaining competitive natural gas and electricity markets, while regulating and overseeing the terms and conditions for energy transactions that continue to be regulated on the traditional cost-of-service basis. The Office of the General Counsel provides legal services and is responsible for the legal phases of the Commission's activities.

Forty percent of FERC's staff focus on energy projects, an area that includes the physical infrastructure of pipelines, dams, and related facilities. These staff are primarily located in the Office of the General Counsel and the Office of Energy Projects. The Office of Energy Projects authorizes nonfederal hydroelectric projects and ensures that dams under its jurisdiction are properly constructed, operated, and maintained. This office also certifies the construction and operation of natural gas pipelines and approves the abandonment of pipelines no longer being used. In addition, the office reviews hydropower and natural gas projects to ensure their compliance with environmental laws.

The remaining 25 percent of FERC's staff are located mostly in administrative and management support offices. These offices are responsible for the agency's planning, budgeting, human capital, information technology, financial management, and related processes. (See fig. 2.)

Figure 2: FERC's Organization



Source: FERC.

FERC's Legislative Authorities for Natural Gas Regulation

Natural gas companies were initially locally franchised monopolies, many of which manufactured natural gas locally from coal. With the discovery of large natural gas reserves in the Southwest in the early 1900s, large interstate pipeline companies soon became a major sector of the natural gas industry, which nonetheless retained strong features of a natural monopoly.[2] In 1938, the Congress passed the Natural Gas Act, which gave the Federal Power Commission (and now FERC) jurisdiction over interstate transportation and sales for resale of natural gas. The act also gave the agency jurisdiction over new construction and abandonment of natural gas pipelines and related facilities.

Under this regulatory scheme, producers located natural gas reserves, drilled wells, gathered the gas, and put it in marketable condition for sale to interstate pipeline companies. After purchasing the natural gas, pipeline companies generally transported and sold the gas to local distribution companies for final sale and distribution to the ultimate consumers, such as homeowners. The interstate pipeline companies also sold some natural gas directly to consumers. FERC regulated the pipeline companies' terms, conditions, and rates for interstate transportation and sale for resale of the natural gas to ensure that they were just and reasonable. State and local

[2] A natural monopoly is a company that becomes the only supplier of a product or service because the nature of that product or service makes a single supplier more efficient than competing ones.

authorities generally set the transportation rates that the local distribution companies charged consumers. FERC and the state and local governments generally set rates on the basis of the companies' cost of providing these services, plus a reasonable rate of return on their investment.

A 1954 Supreme Court decision interpreted the Natural Gas Act as also requiring the Federal Power Commission to regulate the prices that producers charged to pipeline companies in the production area (wellhead) for the natural gas sold in interstate commerce.[3] However, comprehensive regulation of natural gas wellhead prices proved a failure. By the mid-1970s, severe gas shortages occurred as a result of artificially low prices. During cold winters, such as 1976-77, these shortages translated into delivery curtailments for many customers in the northern United States. Responding to these supply problems, the Congress passed the Natural Gas Policy Act of 1978 to begin the phased deregulation of wellhead prices. For the phase-out period, the act established a pricing scheme that encouraged increased natural gas production. Producer price deregulation was completed with the Natural Gas Wellhead Decontrol Act of 1989, which mandated that federal controls over natural gas producer prices end by 1993, when prices would be freely set in the marketplace.

In response to the Natural Gas Policy Act of 1978, FERC reduced regulation of natural gas supplies transported between intrastate and interstate pipeline systems. According to FERC, this breaking down of barriers between the intrastate and interstate markets accelerated a fundamental change in the natural gas industry, leading to marketing natural gas as a commodity distinct from its transportation. Additional changes have occurred in the restructured natural gas marketplace as a result of FERC regulatory action and other developments that are discussed later in this chapter.

FERC's Legislative Authorities for Electricity Regulation

The Public Utility Holding Company Act of 1935 (PUHCA) and the Federal Power Act of 1935 established the basic framework for electric utility regulation for over 40 years.[4] PUHCA was enacted to eliminate unfair practices by large interstate electricity and natural gas holding companies, which evolved and dominated the industry in the 1910s and 1920s, by requiring federal control and regulation of these companies. In 1935, the

[3] *Phillips Petroleum v. Wisconsin*, 347 U.S. 672 (1954).

[4] PUHCA and the Federal Power Act were enacted as part of the Public Utility Act of 1935.

Federal Power Act created the Federal Power Commission, FERC's predecessor, and charged it with overseeing the rates, terms, and conditions of wholesale sales and transmission of electric energy in interstate commerce by public utilities.

This basic legislative framework for electricity went largely unchanged until 1978 when, primarily in response to the oil embargoes and higher energy prices of that time, the Congress passed laws to encourage the development of alternative sources of power and energy efficiency. The Public Utility Regulatory Policies Act of 1978 (PURPA) was enacted, in part, to augment electric utility generation with more efficiently produced electricity and conserve natural gas. The act required all utilities to buy electricity produced by nonutility power production facilities, known as "qualifying facilities." To facilitate entry of these entities into the electric generating market, the Congress exempted them from most regulation under the Federal Power Act and PUHCA, but they had to meet specific ownership and operating requirements.[5] More significantly, by opening wholesale power markets to nonutility producers of electricity, PURPA laid the groundwork for increased competition and a shift in the way that wholesale electricity rates were set. Before implementation of PURPA, wholesale interstate electricity prices were set by FERC on the basis of the seller's costs to generate and transmit the power—known as cost-of-service pricing. Subsequently, under PURPA, states set rates, pursuant to general regulations enacted by FERC, for nonutility qualifying facilities (QF) based on the buyer's "avoided" cost.[6] PURPA allowed these facilities to sell at avoided cost rates because, unlike the utilities, these QFs did not have a large enough market presence to be able to unduly influence prices.

Electricity regulation was significantly changed again with the passage of the Energy Policy Act of 1992 (EPACT). EPACT created a new category of power sellers called exempt wholesale generators (EWG) that are exempt

[5] Qualifying facilities fit into one of two categories: (1) cogenerator qualifying facilities, in which electric energy and another form of energy, such as heat or steam, are produced sequentially using the same fuel source and (2) small power producer qualifying facilities, in which at least 75 percent of energy source inputs are from renewable resources. Both cogenerating and small power producing qualifying facilities cannot have more than 50 percent of their equity interest held by an electric utility.

[6] Avoided costs are the energy and facilities costs that would have been incurred by the purchasing utility if that utility had to provide its own generating capacity. According to FERC, while it certifies and provides general avoided cost QF regulations, states set the QF rates that are often above market rates.

from FERC regulation under PUHCA. In addition, EPACT authorized FERC to require utilities, on a case-by-case basis, to allow competitors to use their transmission lines to sell wholesale electricity, setting the stage for the open-access transmission that exists today. Unlike QFs, these EWGs did not have to meet the same operating requirements, such as having to meet cogeneration and renewable fuel limitations. In addition, utilities are not required to purchase power from EWGs, as they are with QFs. By making it easier for nonutility generators to enter the wholesale market for electricity, EPACT not only expanded competition but also facilitated the shift in how electricity prices were set, since utilities could purchase electricity from EWGs at market-based rates, traditional cost-of-service prices, or a combination of both.

For the electric power industry, FERC does not have legislative authority over electricity generation, construction of transmission lines, intrastate transmission, or retail sales, all of which fall under state or local jurisdiction. FERC also has no direct authority over system reliability—that is, ensuring that consumers can obtain electricity from the system when, and in the amount, they want. This reliability has largely been the responsibility of electric utilities, and, since its creation in 1965, of the North American Electric Reliability Council and member organizations. Currently, an estimated 30 voluntary utility groups are working to improve reliability. Adherence to the standards established by these groups is largely voluntary and therefore subject to the willingness of the utilities to comply.

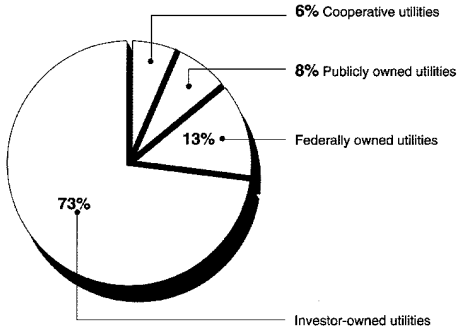
Furthermore, FERC's jurisdiction extends primarily to investor-owned utilities. FERC does not have jurisdiction over federally owned utilities,[7] publicly owned utilities, or most cooperatively owned utilities.[8] These

[7] Although the commission has jurisdiction under sections 211 and 212 of the Federal Power Act to order federally owned utilities to provide transmission in certain circumstances, this jurisdiction is limited. The commission also has limited authority to approve the Bonneville Power Administration's power and transmission rates and, by delegation from the Secretary of Energy, to review the rates charged by other power marketing administrations.

[8] There are nine federal electric utilities: Tennessee Valley Authority, Bonneville Power Administration, Western Area Power Administration, Southwestern Power Administration, Southeastern Power Administration, U.S. Army Corps of Engineers, U.S. Bureau of Reclamation, U.S. Bureau of Indian Affairs, and the International Water and Boundary Commission. Publicly owned utilities include municipal authorities, state authorities, public power districts, and irrigation districts. Cooperatively owned utilities are formed and owned by groups of residents, often in rural areas, and provide service mostly to members.

nonjurisdictional utilities own 27 percent of the U.S. electric transmission system (see fig. 3).

Figure 3: Transmission Ownership in the United States



Source: Energy Information Administration, *The Changing Structure of the Electric Power Industry 2000: An Update*, DOE/EIA-0562(00) (Washington, D.C.: October 2000).

The Nation's Natural Gas and Electricity Industries Are Evolving

For almost a century, the energy industries were regulated as natural monopolies and the entry, prices, and profits of industry participants were controlled. However, during the last 25 years, because of technological and economic developments, these industries, along with other regulated industries such as telecommunications, airlines, and banking, have come under pressure to restructure and move toward greater reliance on competition rather than regulation. A key expectation for restructuring these industries from a regulated environment to competition-based markets was that it would result in improved efficiencies that, in turn, would lead to lower costs and ultimately lower prices for consumers. About two decades ago, the natural gas industry began restructuring. Currently, the focus is on the electricity industry.

The Natural Gas Industry Has Substantially Restructured

The U.S. natural gas industry has evolved from a collection of regulated monopolies to a national system of producers; pipeline, storage, and local distribution companies; marketers; and consumers. In the past two decades since the Congress passed the Natural Gas Policy Act of 1978 to deregulate federal controls over wellhead prices, FERC has issued orders to encourage further competition in the industry. The result of these orders is that the natural gas industry's restructuring is several years ahead of that of the electricity industry.

FERC issued a series of orders during the 1980s and early 1990s to address what it believed was the biggest obstacle to competitive natural gas markets: the inability of natural gas users to gain access through the pipeline systems to competitive natural gas suppliers. These orders—the most notable of which were Orders 436 and 636—opened pipeline transportation to natural gas producers, suppliers, and users on equal terms and eventually resulted in interstate pipeline companies relinquishing their traditional merchant function. FERC issued Order 436 in 1985 to institute open-access, nondiscriminatory pipeline transportation. As a result, natural gas users could buy directly from natural gas merchants in the production area and ship that gas via the interstate pipelines. The pipeline companies could still make bundled sales of the natural gas and its transportation and storage to local distribution companies. Order 636, which was issued in 1992, required the pipeline companies to completely separate or "unbundle" their transportation, storage, and sales services. As a result, natural gas as a commodity was decoupled from gas transportation. Pipeline companies were required to treat other parties wishing to use the pipeline to transport natural gas the same as they would their own affiliated sales services, if they continued to have any. Order 636 also allowed shippers to release to other shippers unneeded pipeline transportation capacity, on either a temporary or a permanent basis, leading to the creation of a secondary capacity market designed to compete with the primary pipeline market.

As a result of this restructuring, producers sell natural gas to a variety of consumers, as well as to brokers/traders and resellers of natural gas. With the removal of federal price controls, producers' prices are determined in the marketplace. In addition, natural gas that is ultimately sold to consumers moves via the pipelines under a variety of contractual arrangements. Natural gas may be sold under contract or on the spot market, where an owner auctions a package of natural gas at a specific location for the price prevailing at that time and place. Buyers and sellers arrange for pipeline capacity to transport their natural gas to market. The purchaser pays the pipeline company for transportation and may also

contract for ancillary services, such as storage, en route. In some transactions, pipeline companies deliver natural gas to customers located directly along the pipeline right-of-way or near enough to a customer-owned pipeline. In other cases, natural gas is delivered to a local distribution company from the pipeline drop-off point, often referred to as the "city gate." The local distribution company operates an intrastate utility regulated by the state public utility commission that delivers natural gas from the city gate to residential, commercial, and industrial users along its route. For residential users, the local distribution company usually purchases the natural gas for resale to them. For commercial and industrial users, the local distribution company is usually delivering natural gas that the users have purchased directly from producers. However, generally speaking, commercial and industrial customers may also choose to buy natural gas from the local distribution company.

For competitive markets, the wholesale price of natural gas sold in interstate commerce is generally determined by the marketplace, subject to FERC's review to ensure that the rates are just and reasonable. For pipelines without competition, FERC sets the rates using the traditional cost-of-service regulatory format.

Natural gas pricing is becoming increasingly complex. One outgrowth of FERC's orders was the creation of new market centers to provide central pipeline interconnections where individuals and companies could come together to buy and sell natural gas. Today, natural gas prices are set at dozens of distribution "hubs" and at 16 city gates. For example, spot-market prices are set for the Henry Hub, a distribution center for natural gas, in Louisiana. In 1990, futures contracts for natural gas delivered at the Henry Hub were first traded on the New York Mercantile Exchange (NYMEX).[9] Since then, NYMEX has created contracts for swapping natural gas at other hubs with gas priced at the Henry Hub. Options contracts are

[9] A futures contract is a risk management tool used in agricultural, metal, and energy commodities markets designed to manage the risk of price changes.

traded on the price spread of Henry Hub gas between different delivery dates.[10]

Another development is the natural gas industry's increasing convergence with the electricity industry. As restructuring of the electricity industry takes place and natural gas has become a major fuel for generating electricity, electric power producers are buying interests in natural gas reserves and/or pipelines as a way to ensure gas supplies for electricity generation. In addition, natural gas producers, pipeline companies, and marketers are also buying interests in the electricity industry, such as in electric power generating plants. The growing complexity and intertwining of these industries further complicates the regulation and oversight of these markets.

The Electricity Industry Is Changing Significantly

When the Federal Power Act was enacted in 1935, the fundamental structure of the electricity industry was based on "vertically integrated" electric utilities, which were single entities that owned generation, transmission, and distribution facilities and sold electricity as part of a "bundled" service to wholesale and retail customers within their geographic area. Most electric utilities built their own power plants and transmission systems, entering into interconnection arrangements with neighboring utilities. Because the utilities operated as monopolies, wholesale and retail electricity pricing was regulated. Rates were derived from a utility's costs plus a fair rate of return on the utility's investment.

As previously described, this industry arrangement of tightly regulated, vertically integrated monopolies and cost-of-service pricing continued relatively unaffected until the late 1970s when the enactment of PURPA began the transition to a more competitive format in which generators of electricity compete for customers and prices are established by the market. In the 1970s, rapid price increases in some parts of the country and significant technological changes in power generation led the Congress to pass PURPA, which requires utilities to purchase power from

[10] Options contracts are unilateral contracts that give buyers and sellers the right to buy or sell a specified quantity of a commodity at a specific price within a specified period of time, regardless of the market price of that commodity. On publicly regulated exchanges such as NYMEX, buyers and sellers are revealed once the transaction is complete. This is different from sales made in nonregulated forums, such as "over-the-counter" or in Internet markets, where the parties are known only to one another or to Internet-service subscribers and the market's operators. These over-the-counter prices (but not the buyers and sellers) are aggregated and reported the next day in the energy trade press.

qualifying facilities and to sell them backup power. As nontraditional power producers, such as qualifying facilities, began to compete in electricity markets, FERC encouraged these new entities by authorizing market-based rates for their electric power sales on a case-by-case basis.

The Energy Policy Act of 1992 authorized FERC to require utilities, on a case-by-case basis, to provide other wholesale buyers and sellers access to their transmission lines and created exempt wholesale generators to further compete with the utilities. FERC began to require utilities to open access to their transmission lines as a condition of approving utility mergers or market-based rates for their power sales. Since the late 1980s, FERC has approved more than 850 applications to sell power competitively in wholesale markets.

In April 1996, FERC issued Orders 888 and 889, opening the transmission systems of public utilities to all qualified wholesale buyers and sellers of electricity. Commonly known as the "open access rule," Order 888 required that transmission line owners offer other transmission users point-to-point and network transmission services under comparable terms and conditions that they provide for themselves. The vertically integrated nature of utilities in the past had not allowed independent power suppliers equal access to transmission systems. By limiting the extent to which independent power suppliers could provide service to electricity customers, growth of competitive power generation markets had been hindered. Order 888 also required that utilities "functionally unbundle" their generation and transmission businesses to prevent favoritism and discriminatory practices in providing transmission services, such as not allowing competitors equal access to transmission lines. This was accomplished by requiring utilities to separate their transmission service functions from other business activities. Order 888 also encouraged utilities to form independent system operators (ISO),[11] to which they could transfer operating control (but not ownership) of their transmission facilities. This could be one solution to the unbundling requirement

[11] An ISO is an entity encouraged by FERC to manage the transmission system as the electric industry in the United States is restructured. An ISO is to control the power system or grid without special interest, and is to own no generation, transmission or load. Therefore, the ISO is intended to run the system fairly, for the benefit of all market participants.

contained in the order. Since Order 888 was issued, six ISOs have been formed and are now operating.[12]

To effectively ensure nondiscriminatory access to the transmission system, up-to-date information about transmission must be unrestricted and public to all transmission users. To meet this need, FERC issued Order 889 requiring all investor-owned utilities to participate in the Open Access Same-Time Information System (OASIS). OASIS is an interactive Internet-based database containing information on available transmission capacity, capacity reservations, and transmission prices. By providing timely access to all qualified users regarding transmission market information, the goal of OASIS was to facilitate the functioning of competitive electricity markets.

In December 1999, FERC issued Order 2000, which asked all transmission-owning utilities, including nonpublic utilities, to voluntarily place their transmission facilities under the control of an appropriate regional transmission organization (RTO). ISOs created under Order 888 would be supplanted by larger RTOs covering the entire nation. FERC's thinking underlying RTOs is that the nation's transmission systems should be brought under regional control in order to eliminate the remaining discriminatory practices in use, better meet the increasing demands placed on the transmission system, improve management of system congestion and reliability, and achieve fully competitive wholesale power markets. Order 2000 does not specifically require RTO participation; however, if a utility opts not to join an RTO, it is required to prove why doing so would harm it.

Since issuing Order 2000, FERC has taken a more aggressive stance on developing RTOs. For example, on July 12, 2001, FERC issued several orders requiring utilities to enter into discussions to form four large RTOs covering the continental United States. FERC subsequently issued an order on November 7, 2001, that reiterated FERC's goals and process for

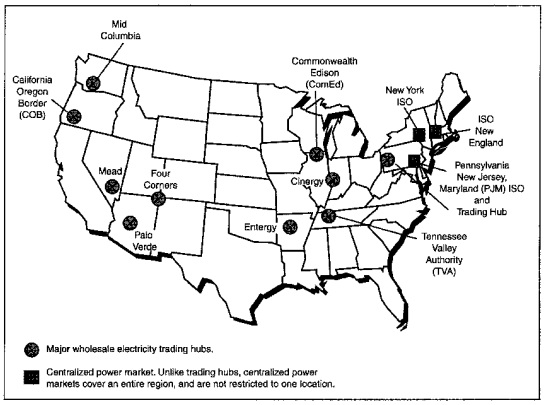
[12] These ISOs are California ISO; ISO New England; Midwest ISO; New York ISO; Pennsylvania, New Jersey, Maryland (PJM) ISO; and Electric Reliability Council of Texas (ERCOT) ISO. FERC approved the Midwest ISO as the first regional transmission organization in December 2001. ERCOT established an ISO in 1996 to satisfy the requirements of the Public Utility Commission of Texas for deregulating the wholesale electricity market in the state. The wholesale market in the ERCOT region is basically isolated from other U.S. markets because its power grid or transmission system has only minor connections to other U.S. transmission systems. FERC has limited jurisdiction over the region because the ERCOT market is essentially intrastate.

creating RTOs. FERC approved the formation of the first RTO—to include the Midwest ISO—on December 20, 2001. This RTO will operate in some 20 states, stretching from New Mexico to the Canadian province of Manitoba. FERC also encouraged another group, the Alliance Companies, to explore joining the Midwest RTO, potentially expanding its scope even further. To address state and industry concerns regarding the merits of forming RTOs, FERC commissioned a study to examine their potential economic costs and benefits. This study, released on February 26, 2002, found that substantial economic benefits, from $1 billion to $10 billion per year, could result from instituting RTOs. However, the study found only minor differences in savings between larger and smaller RTOs.

FERC is also developing a notice of proposed rulemaking to provide a standardized market design for all electric transmission providers. In October 2001, FERC held workshops to discuss core issues related to RTO development, including market monitoring, reliability standards, and market design and structure. FERC subsequently held technical conferences relating to market design for wholesale electric power markets, as well as how responsibility for performing wholesale market functions would be allocated within an RTO region.

With the restructuring that has taken place and FERC's approval of market-based rates for electricity sales, the industry has experienced a significant change in the way power is sold across state lines. Four ISOs—California; Pennsylvania, New Jersey, Maryland; New York; and New England—are currently operating centralized power markets where electricity suppliers submit bids to sell power in regional markets. In these markets, the ISO evaluates the bids and selects the most economical bid to meet energy demand in the region. Another recent development outside of these markets is electricity trading hubs. A hub is a location on the power grid representing a delivery point where power is sold and ownership changes hands. Although each control area on the power grid could become a trading hub, only a few hubs account for the bulk of power trading. Development of electricity futures contracts at NYMEX and the Chicago Board of Trade has contributed to the emergence of these hubs. (See fig. 4 for these major hubs and centralized power markets.)

Figure 4: Major Wholesale Electricity Trading Hubs and Centralized Power Markets



Note: Power trading also occurs at locations not indicated on the map. NYMEX has established electricity futures contracts for the Cinergy, COB, Entergy, Palo Verde, and PJM trading hubs. The Chicago Board of Trade has established electricity futures contracts for the ComEd and TVA trading hubs.

Source: Energy Information Administration, *The Changing Structure of the Electric Power Industry 2000: An Update*, DOE/EIA-0562(00) (Washington, D.C.: October 2000).

Finally, development of Internet-based trading systems, such as EnronOnline, Dynegy*direct*, and Intercontinental Exchange, has further changed the way in which electric power is sold. These systems provide a platform for both physical energy (electricity and natural gas products) and energy derivatives to be bought and sold.[13]

Table 1 describes the major events and milestones that have occurred during the restructuring of the natural gas and electricity industries.

[13] Derivatives are financial instruments based on the value of one or more underlying stocks, bonds, commodities, or other items, such as contracts for future natural gas sale or distribution. Derivatives involve the trading of rights or obligations based on the underlying product but do not directly transfer property.

Table 1: Major Events and Milestones in Restructuring the Natural Gas and Electricity Industries

Event	Natural gas industry	Electric industry
Early steps toward competition	Some large consumers in the interstate market started purchasing gas and pipeline transportation separately—mid 1970s.	Utilities file FERC rates with "up to" cost based formulas—early 1980s. Public Utility Regulatory Policies Act mandates purchases from qualifying facilities—1978.
Exceptions to cost-of-services rates	Natural Gas Policy Act gradually removes some natural gas price ceilings—1978.	PURPA exempted qualifying facilities from cost-of-service regulation. FERC recognizes competitive bidding for new capacity—1988.
Transmission access proposed to dampen anticompetitive behavior and encourage competition	FERC encourages pipelines to provide open-access transportation—1985.	FERC initiates transmission access conditions for market-priced power sales—1990. Energy Policy Act authorizes FERC to order transmission access to encourage competition—1992.
Standards to mitigate monopoly control in transmission announced	Order 636 issued in 1992: • Comparable transmission and storage open-access required. • Functional unbundling of product and transportation sales required. • Pipeline companies allowed to make market-priced gas sales through affiliates. • Firm transportation customers get flexible receipt and delivery points.	Orders 888 and 889 issued in 1996: • Nondiscriminatory, comparable open access required. • Functional unbundling generation and transmission businesses. • Investor-owned utilities required to participate in OASIS. Order 2000 issued in 1999: • Transmission owning utilities encouraged to place transmission facilities under the control of RTO.
Access to information to support market functions	Trade press publishes spot gas prices—1989. FERC mandates individual pipeline electronic bulletin boards—1992. FERC mandates standardized Internet communication protocol—1997.	Market-based pricing includes requirements for electronic bulletin boards—1992. Energy Policy Act requires public capacity reporting—1992. FERC orders OASIS—1996.
Market characteristics evolve	Company consolidation starts—mid 1980s. Product markets active; prices transparent—1987. Gas marketing evolves as an unregulated industry—1987. NYMEX futures contract for Henry Hub gas—1990. Robust market centers/hubs for physical trade—1993. Futures markets mature with large consumer access to transportation available in most states—1994. Internet trading of gas and transmission rights—1999.	Company consolidation starts—late 1980s. Spot and forward markets still largely restricted to utilities—1995. Neither transportation nor product prices are transparent yet—1995. Development of a futures market hindered by a lack of a standardized spot market for benchmarking. New entrants are trying to find/produce niches. Innovators hope to combine gas and electric market instruments for added value—1995.

Source: Adapted by GAO from Energy Information Administration, *Restructuring Energy Industries: Lessons from Natural Gas*, Natural Gas Monthly (Washington, D.C.: May 1997).

Objectives, Scope, and Methodology

The Chairman of the Senate Committee on Governmental Affairs and Senator Carnahan asked us to determine how FERC has revised its approach to regulating and overseeing the natural gas and electricity industries in response to the transition to more competitive markets and identify the major management challenges that FERC faces to effectively regulate and oversee these competitive markets.

To address both these objectives, we reviewed pertinent documents and obtained information and views from a wide range of FERC officials and stakeholder representatives. We obtained information and views from FERC and stakeholder representatives through a variety of means, including interviews and surveys. We interviewed the Chairman of FERC and the other current Commissioners, as well as three former Commissioners/Chairs who served at FERC within the past 5 years. In OMTR, we interviewed all the managers at the division head level and above, including the director and deputy director of the office. We also interviewed the group managers of the office's Divisions of Market Development and Market Information. For the Office of the General Counsel, we interviewed the general counsel, deputy general counsel, and the lead counsels for the Market Oversight and Enforcement section and the Markets, Tariffs, and Rates section. The two sections directed by these lead councils advise OMTR and the Commissioners on regulation of the natural gas and electric industries. In addition, we interviewed the team leaders and various members of the joint OMTR and Office of the General Counsel teams that FERC formed in 2000 to review the nation's wholesale electricity (bulk power) markets. Furthermore, we interviewed the deputy director for FERC's Office of Strategy and Organizational Management and the agency's director for human resources management.

In addition to our interviews, we conducted a survey of the staff in OMTR, and staff in the Office of the General Counsel's sections for Markets, Tariffs, and Rates and Market Oversight and Enforcement, up to and including those at the division or section director level. The survey was conducted using a self-administered electronic questionnaire posted on the World Wide Web. We sent e-mail notifications to 384 FERC staff beginning on December 14, 2001. We then sent each employee who was surveyed a unique password by e-mail to ensure that only members of the target population could participate in our survey. We closed the survey on February 8, 2002, having received a total of 271 responses, for an overall response rate of 71 percent. A copy of this survey with the quantitative results can be found in appendix II.

The practical difficulties of conducting surveys may introduce errors into the results. Although we administered our survey to all known members of the population of employees, and thus our results are not subject to sampling error, nonresponse to the entire survey or individual questions can introduce a similar type of variability or bias into our results—to the extent that those not responding differ from those who do respond in how they would have answered our survey questions. We took steps in the design, data collection, and analysis phases of our survey to minimize population coverage, measurement, and data-processing errors, such as checking our population lists against known totals of employees, pretesting and expert review of questionnaire questions, and follow-up with those not reachable at original addresses or otherwise not immediately responding.

We also spoke with representatives of a wide range of FERC stakeholders, including the National Energy Marketers Association, the National Association of Regulatory Utility Commissioners, the Electric Power Supply Association, and the American Public Gas Association. In addition, we interviewed representatives, primarily from the market monitoring units, of the New York ISO, ISO New England, the California ISO, and PJM ISO. We did not interview representatives of the Midwest ISO because it had just begun operations toward the end of our review. Furthermore, we visited three major energy trading companies to discuss the information they use in making energy trades.

We also surveyed the chairs of the state regulatory commissions or boards from 48 states and the District of Columbia via e-mail to ask them for comments, from their states' perspective, on FERC's regulation and oversight of the natural gas and electricity industries.[14] The initial e-mail was sent on November 15, 2001, with a follow-up reminder sent on December 10, 2001. The final deadline for submissions was December 21, 2001. We received responses from 30 of the 49 state commissions or boards surveyed.

In addition, we reviewed laws and regulations pertaining to FERC's responsibilities for regulating and overseeing the natural gas and electricity industries. We reviewed pertinent FERC documents, including annual reports; budget requests; strategic and annual performance plans;

[14] We did not survey Hawaii, where FERC does not have regulatory jurisdiction, nor did we survey Nebraska, where no state regulatory body exists.

orders; case filings; studies; reports; human capital analyses; speeches and congressional testimony by FERC Chairmen, Commissioners, and other officials; and staff research papers. We also reviewed appropriate documents from outside sources, including the Department of Energy's Energy Information Administration, the North American Electric Reliability Council, the Congressional Research Service, ISOs, academia, and other natural gas and electricity industry experts. Furthermore, we drew on our prior work in the areas of electricity, natural gas, and human capital management.

We conducted our work from June 2001 through April 2002 in accordance with generally accepted government auditing standards.

Chapter 2: FERC Has Not Yet Defined and Implemented an Effective Approach to Monitor Competitive Energy Markets

FERC has recognized, since the early 1990s, that it needs to change its approach for regulating and overseeing the natural gas and electricity industries in response to their evolution from regulated monopolies to competitive markets. However, FERC has struggled to define and implement a comprehensive regulatory and oversight approach, and its efforts to monitor these markets, to date, have been incomplete or of limited effectiveness. Moreover, the agency's outdated legislative framework and frequent leadership changes over the last few years have contributed to further limiting its progress in developing and implementing an effective approach.

FERC Recognizes That It Needs a New Approach for Competitive Energy Markets

For nearly a decade, FERC has recognized that it needs a new approach for regulating and overseeing the emerging competitive energy markets. With the evolution to market-based rates for natural gas and electricity, FERC has concluded that its approach to ensuring just and reasonable prices needs to change: from one of reviewing individual companies' rate requests and supporting cost data to one of proactively monitoring energy markets to ensure that they are working well to produce competitive prices. From 1994 to the present, the need for this change has been a reoccurring theme in a variety of key FERC documents, such as its annual budget requests, strategic plans, and performance reports.

For example, we found that as early as February 1994, in its fiscal year 1995 budget request to the Congress, FERC stated that the centerpiece of its strategy for the natural gas and electricity industries was to encourage competitive market processes wherever appropriate. In this document FERC noted that while competitive forces could benefit energy customers all over the country, harnessing the benefits of competition without allowing abuses of market power required many regulatory innovations, including many new approaches to oversight. FERC concluded that the electricity industry would see significant changes under the Energy Policy Act of 1992, largely through increasing competition among electric power producers and more open transmission access, and that these changes would inevitably require new long-term policy development as well.

The need for a new regulatory and oversight approach has been reiterated by FERC throughout the last several years in a variety of other key documents, such as the following:

- In its fiscal year 1996 budget request, dated February 1995, FERC stated that its goal was to find ways to regulate natural gas and electric utilities effectively in order to protect consumers while working with competitive commodity markets. FERC stated that it expected to continue the shift in emphasis away from its traditional routine casework of reviewing companies' rate filings and more toward monitoring and compliance. It stated that increasingly, its approach to regulation would be to monitor the industries it regulates and act only when there is a clear need to do so.

- In its first strategic plan for fiscal years 1997 through 2002, issued in September 1997, FERC again stated that, at the most basic level, the agency was moving away from a traditional command and control approach of setting individual companies' rates to economic regulation.[1] The plan anticipated the need to respond to the evolving natural gas and electric power industries with increased flexibility and speed. FERC placed particular importance on the convergence of the natural gas and electric industries and on the need to coordinate with other federal agencies and states. The plan also noted that as the need for regulation in the industries changed, the agency must change to respond in "real time" to these needs.

- In its State of the Agency report for fiscal year 2000,[2] FERC noted that like all regulatory agencies, it faced uncertainty about its resources and its future mission. The report concluded that to ensure consumer confidence in competitive energy markets, FERC must adapt the way it does business to address the real-time needs of market participants and changing market dynamics, while still maintaining the integrity of its regulatory functions.

- In its most recent budget request for fiscal year 2003, dated February 2002, FERC again stated that it needs a much stronger ability to recognize and respond to problems in the markets. FERC further stated that it needs to recognize problems when or before they happen and craft solutions

[1] The Government Performance and Results Act of 1993 required almost all federal agencies to, among other things, develop strategic plans covering a period of at least 5 years. These strategic plans were to include the agency's mission statement, long-term general goals, and the strategies that the agencies will use to achieve these goals. Agencies were to submit their first strategic plans to the Office of Management and Budget and the Congress by September 30, 1997.

[2] Federal Energy Regulatory Commission, *First Annual State of the Agency Report, Fiscal Year 2000* (Washington, D.C.: October 2000). FERC has not issued similar reports for subsequent fiscal years.

quickly and also be able to police individual behavior in markets much more effectively than in the past.

FERC Has Struggled to Define and Implement a New Approach

Despite its long-standing awareness of the need for a new regulatory approach, FERC has struggled to define the specific strategies, information, processes, and activities that it will use to regulate and oversee competitive energy markets. Various planning and reengineering initiatives that FERC has recently undertaken have not been successful in defining and implementing a comprehensive approach for these markets. Moreover, while California's energy problems in 2000 provided a "wake up call" for the agency and the impetus for a greater focus on market oversight functions, they also delayed the agency's efforts to establish an effective market oversight program by diverting substantial management attention and resources.

FERC's Strategic Planning Process Has Not Provided the Goals, Strategies, and Milestones to Implement a New Approach

FERC's strategic planning process helped lay the groundwork for the agency to begin revising its regulatory and oversight approach. However, the process has not produced the specific goals, strategies, and milestones to effectively make the change. FERC first issued its strategic plan in September 1997, and has since revised it twice, once in September 2000 and again in September 2001. The overall direction of the strategic or general goals and objectives set out for natural gas and electricity in these versions has essentially remained the same. Although the 2001 version of the plan provides greater and more explicit focus on FERC's oversight and monitoring of the markets than earlier versions, it still lacks key details on how the strategic goals and objectives will be accomplished and how progress in achieving them will be assessed.

FERC Has Been Slow to Explicitly Incorporate Energy Market Oversight into Its Mission Statement

An agency's statement of its mission is a critical element of its strategic plan. It is intended to bring the agency into focus, explain why the agency exists, and tell what it does. FERC's mission statement has only very recently explicitly recognized oversight of the energy industries as an important part of its mission. The mission statement in FERC's 1997 version of its strategic plan essentially stated that the agency regulates the energy industries to ensure that the rates, terms, and conditions of service for the industries are just and reasonable. The 2000 version of the mission statement provided a more direct focus on markets by stating that the agency, in regulating key interstate aspects of the energy industries, chooses regulatory approaches that foster competitive markets whenever possible and ensures access to reliable service at a reasonable price. However, it did not explicitly mention oversight of the industries or markets. The 2001 version does not refer to competitive markets but

instead states that FERC's mission is to regulate and oversee the energy industries in the economic and environmental interest of the American public. (See table 2.) According to FERC, "[t]he California crisis showed that the need for good oversight and investigation is not only important but also far more urgent than we (or most others) had fully understood."

Table 2: FERC's Statement of Its Mission in the 1997, 2000, and 2001 Versions of Its Strategic Plan

Version	Mission statement
1997	The Commission regulates, in the public interest, essential aspects of four of the nation's critical energy industries: electric power transmission and sales for resale, natural gas transportation and sales for resale, oil pipeline transportation, and nonfederal hydroelectric power. The Commission ensures that the rates, terms, and conditions of service for the electric power, natural gas, and oil industries are just and reasonable and not unduly discriminatory or preferential, and that licensing, administration, and safety actions for the hydropower industry and other approvals for all four industries are consistent with the public interest.
2000	The Commission regulates key interstate aspects of the electric power, natural gas, oil pipeline and hydroelectric industries. The Commission chooses regulatory approaches that foster competitive markets whenever possible, assures access to reliable service at a reasonable price, and gives full and fair consideration to environmental and community impacts in assessing the public interest of energy projects.
2001	The Federal Energy Regulatory Commission regulates and oversees energy industries in the economic and environmental interest of the American public.

FERC's Strategic Goals and Objectives Have Focused More on Market Development Than Market Oversight

The goals and objectives that FERC has set out in the initial versions of its strategic plan have focused more on efforts to foster the development of competitive markets than on their oversight. For example, the 1997 version of the plan contained no strategic goals and one strategic objective specifically addressing oversight of market rules and behavior. (See app. I for FERC's principal strategic goals and objectives relating to energy markets.) That objective—for constraining market power—states that market participants will have confidence that natural gas markets, electric markets, and all transportation services are working efficiently and fairly and that market participants are not subject to abuses of market power. The plan stated that FERC would monitor the electric utilities and assess whether they can exercise market power that could adversely affect wholesale electric prices. In addition, FERC would respond appropriately to market power issues in the context of market-based pricing and in reviewing the effects of mergers on competition. However, the plan offered no details about how FERC would monitor energy markets beyond

its approval of individual companies to sell electricity at market-based rates and review of proposed mergers of energy companies.

Similarly, FERC's 2000 version of its strategic plan contained one goal for energy markets. That goal—to benefit consumers by providing a fair, open, and efficient regulatory foundation for competition—had four objectives. As with the 1997 version of the plan, one objective was to constrain market power. In addition, monitoring energy markets was included as a subobjective under the general objective to nurture competitive market institutions. FERC stated that it must be able to monitor markets so that it can follow events, such as significant price spikes, and react appropriately. To fulfill its market monitoring strategy, the plan stated that FERC would (1) develop up-to-date, flexible information systems, (2) use investigations and audits as valuable market monitoring tools, and (3) begin to publish an annual report on the state of the markets. According to the plan, to constrain market power, FERC would detect and respond to all forms of market power and use enforcement and litigation as necessary to remedy anticompetitive behavior. The plan also stated that market monitoring could help FERC detect potential or actual market power abuse and that FERC would try to limit operations of existing and emerging entities that may possess market power. Although the 2000 version provides more results-oriented goals and objectives and a greater elaboration of strategies than the 1997 version, it does not provide the details and measures to allow the agency and the Congress to assess whether the goals and objectives were achieved and the strategies were effective.

Only recently, in its 2001 revision, has FERC increased the strategic plan's emphasis on market oversight and improved its description of the strategies that will be used to achieve the goals and objectives.[3] The Chairman of FERC told us that making competitive energy markets work well depends on (1) an adequate delivery or transmission infrastructure to ensure that sufficient supplies of energy are available to create an environment where competition can succeed, (2) a market structure and market rules that ensure competition, and (3) effective oversight to identify market structures and rules that do not work well and market participants that engage in anticompetitive actions. The Chairman said that when he arrived at FERC in the summer of 2001, he found that FERC

[3] FERC's 2001 revision was not a complete update of the strategic plan document. Instead, new strategic goals and objectives were developed and made available on FERC's Internet Web site, and the agency's fiscal year 2003 budget request provides information on the new strategic goals and objectives and the strategies to achieve them.

had been working on the first two items—the infrastructure and the market structure and rules—but was doing little in the way of effective market oversight. As a result, he revised the strategic plan to provide a balanced approach that covers all three factors.

While the 2001 version provides more information than earlier versions on the strategies to be used to achieve the agency's goals and objectives, the plan still provides few details on how FERC will work with market participants to accomplish the goals and objectives. The plan also does not have quantifiable outcome measures that can be used to assess FERC's progress in achieving the goals and objectives over the period of the plan. For example, to protect consumers, the plan states that FERC will detect abuses of market power quickly. To do this, FERC will pay close attention to complaints as it receives them and will also develop its analytical capabilities. However, there is no information on what new actions FERC will take to pay close attention to the complaints or what actions it will take to develop its analytical capabilities. There are also no quantifiable outcome measures to evaluate FERC's success in achieving this goal and its related objectives.

FERC's Major Reengineering Project Did Not Address Fundamental Oversight Issues

In December 1997, FERC launched a major management review and reengineering project, referred to as "FERC First." According to FERC documents, the project was undertaken as a result of the 1997 strategic planning process, during which the agency concluded that it would have to move away from traditional command and control approaches and move toward economic regulation of the evolving energy markets. The project was to assess the external influences affecting the agency's operations, as well as the adequacy of the agency's processes, employee development practices, information technology infrastructure, communication, and other business practices. According to FERC, the project's costs from February 2, 1998, to March 31, 2000, totaled $20.1 million, including about $7.5 million in agency personnel costs and about $7.7 million for the two principal consulting firms that it used.

FERC First resulted in a number of changes, including the following:

- a new organizational structure for the agency, including the creation of the Office of Markets, Tariffs and Rates (OMTR) to focus on energy markets;
- a formal process for strategic planning and management with a focus on energy markets, energy projects, and the management services needed to support them;

- the combination of responsibilities and personnel for natural gas and electricity to reflect the convergence under way in these industries;
- the modification of work processes to minimize hand-offs from one person to another and one office to another, reduce the number of reviews, and integrate them with information technology;
- the increased use of teaming of staff, within and across groups, to perform the agency's work; and
- new criteria for selecting and training managers that emphasized leadership qualities over technical expertise.

Although well intentioned, FERC First is generally considered by most FERC employees that we contacted to have failed in achieving its objectives. For example, 74 percent of the employees responding to our survey believed that FERC First had improved the agency's ability to effectively monitor or regulate energy markets to little or no extent. In contrast, 4 percent of those responding said that it improved FERC's ability to a great or very great extent. Furthermore, 80 percent of them believed that FERC First had improved their ability to perform their job duties to little or no extent. In contrast, 6 percent of those responding said it improved their ability to a great or very great extent. While many employees that we contacted told us that overall FERC First was a failure, several stated that it was a "disaster." Common concerns cited by employees included (1) the project took too long and diverted too many agency resources for the limited number of changes that resulted and (2) it made the agency less effective rather than more effective.

Moreover, FERC First did not bring about the fundamental changes needed to implement a new regulatory and oversight approach for competitive energy markets. For example, although FERC First established OMTR to give more priority to developing and monitoring competitive energy markets, OMTR has had difficulty defining the specific strategies, information, processes, and activities that it will use to oversee these markets. In October 1999, the director of OMTR said "[w]e have to decide what we want to do with markets, how much resources we want to devote to the different views, what information will we need from outside the building to do our job, what type of IT [information technology] hardware and software will we need to do that, what type of skill sets of people will we need." In August 2000, when FERC hired a director for OMTR's Division of Energy Markets, these details had still not been determined. At that time, the California energy problem had occurred and,

according to FERC officials, the Markets Division devoted most of its attention and resources to responding to the California problem over the next year.

California's energy problems in 2000 forcefully demonstrated what could result when markets do not work as intended. Ironically, while the California problem was, in the words of several FERC officials, a "wake up call" for the agency, it also delayed the agency's efforts to establish an effective market oversight program by diverting substantial management attention and resources away from this task. The California problem was shortly followed by the bankruptcy of the Enron Corporation, again causing OMTR and its Markets Division staff to become involved in addressing concerns related to this new crisis.

Consequently, although it has been almost 4 years since the creation of OMTR was announced, FERC has not been able to devote the time and attention needed to resolve the fundamental issues relating to its market oversight function. FERC currently has two task forces working to determine its information needs for market oversight and is still in the process of developing a working definition for market power. According to industry experts that we spoke to, FERC's lack of progress in clearly defining its market oversight function has eroded their confidence in the ability of the agency to provide the level of regulation and oversight needed for the emerging energy markets.

FERC's Market Oversight Initiatives Have Been Incomplete or Ineffective

FERC has initiated several actions to enhance its oversight of competitive energy markets; however, most of these actions have been incomplete or limited in their effectiveness. Recent FERC oversight initiatives have included (1) creating a Market Observation Resource (MOR) room to collate information on energy markets in a user-friendly format, (2) conducting a series of studies to assess the state of the wholesale electricity (bulk power) markets, and (3) requiring independent system operators (ISO) to establish market monitoring units. However, to date, the MOR room and the bulk power studies have had limited results beyond increasing FERC staff's knowledge about competitive markets, and the ISOs' market monitoring units provide only limited coverage of the nation's energy markets.

The Market Observation Resource Room Has Yet to Fulfill Its Potential

To more effectively monitor increasingly competitive energy markets, in mid-2001 FERC established the MOR room at its Washington, D.C., headquarters. This room, which was patterned after market operation centers or rooms of ISOs and major energy trading companies, uses computers and various software packages to make large amounts of data on natural gas and electricity markets available in a useable format. FERC created the MOR room to serve as a central data source, an education center for the agency's staff, and a regulatory and oversight tool. Since establishing the room, FERC has been acquiring and testing market reporting services and software programs while building an easily retrievable database. However, FERC has not yet been able to use the MOR room to its full regulatory and oversight potential because (1) the data available through the facility are mainly limited to those that are available free of charge, (2) additional data needs for the agency have not yet been determined, and (3) an overall regulatory approach has not been developed. Instead, the MOR room serves principally as a technical learning resource for data analysts in OMTR and as a convenient market information resource for the agency's staff.

The MOR Room Is Becoming a Central Data Source but Currently Lacks Data on Critical Aspects of Energy Markets

While the MOR room is becoming a central data source for FERC, the information that it contains is limited for effective monitoring and oversight of energy markets. Currently, the MOR room provides FERC staff with both commercial and proprietary information services, ranging from Bloomberg Professional Energy service to the PJM E-Data for the Pennsylvania, New Jersey, Maryland (PJM) ISO's mid-Atlantic electricity markets. Electricity market data provided by these services include prices on the spot market and for futures contracts, plant outage information, business news, and historical data for trend analysis. For example, FERC subscribes to FriedWire, which tracks supply, demand, price, and transmission data. Natural gas market data include spot and futures prices and market commentary, storage levels, imports and exports, and supply/demand statistics. The MOR room receives detailed and timely reports about energy prices on regulated exchanges, such as natural gas futures contracts for the Henry Hub traded on the New York Mercantile Exchange (NYMEX). In addition, several weather services are available to monitor changing conditions nationwide, as weather and climate affect energy supply and demand in both spot and futures markets.

However, the MOR data do not yet include detailed information about energy prices on "exempt" commercial markets, such as the UBS-Warburg,

Dynegy*direct*, and Intercontinental Exchange (ICE).[4] Although FERC staff can view natural gas and electricity prices free of charge from the UBS-Warburg, Dynegy*direct*, and ICE Web sites to track general market behavior, FERC would need to become a paying subscriber for these services to routinely obtain the names and other details of the parties trading in these exempt markets. This information would be necessary, for example, if FERC needed to identify instances of power companies or traders exercising excessive market power. Similarly, the MOR room does not receive timely information about over-the-counter markets—where informal dealings that are not federally regulated occur. Some over-the-counter sales in which two parties buy and sell natural gas contracts privately, and offsetting trades known as "swaps," are aggregated and reported the next day in the energy trade press; others are aggregated from a NYMEX report. In commenting on a draft of our report, FERC said it may not have jurisdictions over these trades and, therefore, may not have access to this information. However, we believe that unless FERC staff can regularly track these reports and then compare them to simultaneous behaviors by participants in other markets, it would be difficult to identify instances of market manipulation.

FERC Is Identifying Additional Market Information Needs, but Its Progress Has Been Slow

Since the summer of 2001, FERC has established two teams—the Review of Information Collection Team and the Comprehensive Information Assessment Team—to take stock of the agency's current and future market information needs. These teams were tasked to identify information that FERC currently collects and additional information that it might need. To date, neither team has completed its work, although their initial findings highlight some of the difficulties FERC faces in obtaining additional data.

For example, the Review of Information Collection Team is seeking to learn precisely what data the agency now collects. As of January 31, 2002, the team has determined that FERC has more than 50 active information collection and reporting requirements for the energy companies it regulates and oversees, and that FERC receives about 33,600 industry

[4] UBS Warburg and Dynegy*direct* are "bilateral" electronic traders that, like the once dominant market-maker Enron, always take one side of a buy or sell transaction. ICE is a "multilateral" electronic trader, which invites and matches buy and sell orders for other customers.

responses annually.[5] According to the team's supervisor, the team's effort has not been considered a high priority within FERC. He predicts that it may be several more months until the team completes its detailed assessments of the data, and more than a year until proposed regulations to collect these data can be developed.

Similarly, the Comprehensive Information Assessment Team is identifying the information that the agency will need in order to more effectively regulate and oversee emerging energy markets. The team has already identified about 80 information "needs" for FERC. A critical challenge, according to FERC officials, is to transform this list of needs into a practical set of data requirements. To do this, FERC must first decide how aggressively it will be monitoring energy markets; however, this decision has yet to be made by the agency.

A key feature of FERC's data collection plans is to have other organizations such as federal and state agencies, commercial sources, trade associations, and regional transmission organizations provide FERC access to much of the information needed to monitor energy markets. However, at this point, it is unclear how FERC will ensure that these data are accurate and reliable. Nor is it clear how FERC and its data sources will standardize the data and pay for their collection. Another issue to be addressed is how FERC will integrate these new data requirements with the data already available in the MOR room.

FERC plans to review the results of the two information teams later this spring, and then hold meetings and workshops with market participants. More than likely, any new data identified as important to FERC's market monitoring efforts will not be formally required from market participants until 2003. Moreover, as required by the Office of Management and Budget, FERC will have to offset any new information requests from the industry by eliminating existing ones. One FERC official told us the agency can fulfill this requirement by eliminating certain filings required under the cost-of-service regulation that may no longer be relevant.

[5] In 2000, FERC set a goal to reduce paper filings by 90 percent within 2 years, although currently only four of its forms must be filed electronically and another four may be at the filer's discretion.

The MOR Room's Use as a Regulatory and Oversight Tool Is Largely Undecided

When first created, the MOR room was expected to showcase "the important function of monitoring and assessing the energy market." However, because FERC has not determined how it will regulate and oversee competitive energy markets, the MOR room's use, as a regulatory and oversight tool, remains largely undecided and untapped. For example, FERC officials that we spoke with were not aware of any enforcement actions that had been initiated through use of the MOR room or any market problems detected elsewhere in the agency that had been confirmed or refuted with MOR room data. Currently, the MOR room serves principally as a technical learning resource for data analysts in OMTR and as a convenient resource for the agency staff who prepare the daily *Energy Market Report* and monthly *Energy Markets Review*. These publications keep FERC Commissioners and senior staff aware of news and market events, such as energy trading companies' financial problems, power-plant outages, and energy supply and price trends.

Nonetheless, one energy data analyst who helped design and now operates the MOR room told us that it is likely to become an integral part of FERC's proposed new Office of Market Oversight and Investigation, which is intended to concentrate FERC's market-monitoring resources in one work group (see ch. 3 for more detailed information on this new office). But just how the MOR room will assist the new office has yet to be decided. The extent to which the MOR room can contribute to FERC's regulation and oversight of energy markets also depends on how FERC decides to divide market monitoring responsibilities with other entities, such as the regional transmission organizations. These decisions also have yet to be made.

FERC's Bulk Power Studies Were Not an Effective Oversight Tool

As another oversight initiative, on July 26, 2000, FERC issued an order directing its staff to undertake an investigation of the nation's wholesale electricity (bulk power) markets and report the results by November 1, 2000. The investigation was ordered because the nation's bulk power markets were in different stages of transition, and some areas of the country had experienced extreme price fluctuations. By reviewing technical or operational factors, federal or state regulatory prohibitions or rules, market or behavioral rules, and other factors affecting the reliability or competitive pricing of electricity in these markets, the investigation was to determine whether the nation's bulk power markets were working efficiently.

FERC assigned a study team for each of the five regions covering the continental United States: the northeast, southeast, midwest, west, and Electric Reliability Council of Texas (ERCOT) regions.[6] The teams took about 2 to 3 months to conduct the investigations and write their reports. They reviewed publicly available data and reports and, with the exception of the ERCOT study, obtained input from market participants and others, such as ISOs and state public utility commissions, and also requested specific market information, such as market participants' data on bids during the period.

The final reports from each team generally included data on electricity supply and demand, transmission systems, the regulatory and institutional environment, market design, prices during the summer of 2000, factors affecting these prices, and issues relating to inefficiencies or improvements needed in the markets' design or operations.[7] In addition, the reports generally provided policy options for the Commission, such as potential ways to correct the conditions that led to price spikes, improve market rules, or improve access to the transmission systems to increase competition.

Instead of serving as an effective oversight tool, however, these studies mostly provided FERC staff an opportunity to learn about electricity markets. The study teams were not allocated much time and lacked the expertise and data to provide the depth of investigation needed. According to many of the study team leaders that we talked to, when the studies started the teams knew little about the markets they were examining and they had only about 3 months to complete the work and prepare the reports. Most of the team leaders and members said that more time, more data, and/or staff with different skills or expertise would have been needed to perform in-depth studies. The types of staff skills or expertise cited as being needed included more knowledge of economics and market

[6] ERCOT established an independent system operator in 1996 to satisfy the requirements of the Public Utility Commission of Texas for deregulating the wholesale electricity market in the state. The wholesale market in the ERCOT region is basically isolated from other U.S. markets because its power grid or transmission system has only minor connections to other U.S. transmission systems. FERC has limited jurisdiction over the region because the ERCOT market is essentially intrastate.

[7] On February 1, 2001, FERC staff issued a report on the bulk power markets in the Northwest during November and December 2000. This report, which was an extension of the November 1, 2000, report on the west region, focused on the rapid increase in electric power prices during these 2 months.

operations and skills in compiling and analyzing large amounts of data. According to FERC management, it became clear during these investigations, that the agency did not have enough staff who could analyze the relevant market information. This shortage related both to skills in finding, manipulating, and analyzing large data sets and to economic and other expertise in focusing information analyses on critical market questions and interpreting the results.

Most of the study team leaders and members we spoke to indicated that periodic bulk power studies could be a useful oversight tool for FERC if they were done in more depth. While the studies provide some important baseline data on these markets, FERC has no plans to update the bulk power studies. As an alternative, it proposes to conduct periodic assessments of market performance, supplemented by other reports. In its fiscal year 2003 budget request to the Congress, FERC stated that it plans to publish semiannual seasonal market assessments of major regional markets for both natural gas and electric power. These assessments are to report on a series of objective measurements for each market, such as basic supply-demand balances and the degree of market concentration. They are to also report on the markets' experience with current market rules and on major vulnerabilities, if any, that might threaten to disrupt the markets in the future. FERC plans to supplement these assessments with other periodic reports, including bulletins that analyze fast-breaking market developments. According to FERC, information will come from its MOR room, industry contacts, and close coordination with the market monitoring units (MMU) of the yet-to-be formed regional transmission organizations. These supplemental reports will also include analyses of apparent market anomalies—for example, instances of high prices seen in unexpected places or apparently abnormal volumes of trading transactions.

However, it is likely to be some time before FERC can fully implement these plans. FERC anticipates that the market performance measurements to be used for the seasonal assessments will be finalized during 2003. In addition, the MMUs of the regional transmission organizations (RTO) may not be operational for up to 3 years. FERC is depending on these units to provide much of the data and analysis that it will use for the seasonal assessments and the other reports. As a result, until these new analyses are available, it appears that FERC will not be conducting detailed evaluations of the markets.

ISOs' Market Monitoring Units Provide Oversight Support but Do Not Cover All the Markets

The formation of ISOs provided FERC additional market monitoring support for certain energy markets. Under Order 888, FERC gave public utilities the option to create ISOs to independently operate their electric transmission systems and thereby meet the requirement for separating, or unbundling, interstate wholesale power service from transmission. In approving their formation and use, FERC required ISOs to, among other things, establish a market monitoring unit. MMUs are required to develop market monitoring plans, which must be approved by FERC, and periodically report on their monitoring activities.

Although MMUs play an important market oversight function, their coverage of the nation's electricity markets is limited. Because FERC made the formation of ISOs voluntary, most of the nation is not covered by an ISO, and therefore is not subject to monitoring by an MMU. Currently, FERC has approved five ISOs that cover only parts of the United States. These include the New York ISO; ISO New England; and PJM ISO in the Northeast and the California ISO in the West. The Midwest ISO, covering at least parts of several states in the Midwest from Canada to Kentucky, began selling transmission service in February 2002 but had not yet established an MMU. There are no ISOs operating in the Southeast, the West outside of California, and much of the Midwest. Therefore, market monitoring responsibilities for these areas fall to FERC.

Moreover, the MMUs we contacted—California, New York, New England, and PJM—primarily focused their monitoring activities on reviewing market transactions for abuses of market power by market participants and for market design problems within their particular markets. According to these MMU officials, the strength and value of an MMU's market monitoring activity is in its ability to review minute-by-minute transactions looking for anomalies in market behavior. They believe that FERC's market monitoring role is better suited to evaluating overall market performance at the national or regional level. According to an official from PJM's MMU, FERC has the luxury to look at the overall market picture from a policy perspective, whereas MMUs are down in the trenches dealing with detailed information. The MMUs told us that FERC should leave the responsibility for monitoring daily market transactions to MMUs and concentrate on the larger policy issues.

Finally, MMUs employ different strategies and techniques in reviewing market transactions, which may limit the usefulness of the information they provide to FERC. FERC requires that the MMUs independently and objectively monitor and report on the markets operated by ISOs and that the MMUs' market monitoring plans be designed to ensure competition,

prevent any undue influence by market participants, and correct any design flaws. FERC allows MMUs flexibility with respect to the scope of their monitoring and how it is carried out. As a result, the four MMUs we contacted varied in their size, operations, and focus. For example, the MMUs of the New York and PJM ISOs take different avenues to identifying and mitigating or correcting market power abuse.[8]

Because of these differences in operation, the information provided to FERC by MMUs may not be comparable and may make it significantly more difficult for the agency to develop a comprehensive nationwide analysis of energy markets. This issue will become more important as FERC approves the creation of the larger RTOs under Order 2000 to replace ISOs. FERC is currently developing a standardized design for the RTOs' market monitoring function and the types of market monitoring information that they will be required to provide the agency.

FERC's Outdated Legislative Framework and Frequent Leadership Changes Have Contributed to Its Difficulty in Developing a New Regulatory Approach

FERC's legislative framework of regulatory and oversight authorities has remained essentially the same, even as the energy industries have undergone substantial restructuring. As a result, FERC is struggling to develop and implement a new regulatory and oversight approach for these emerging markets because it is using authorities that were designed when the industries operated as regulated monopolies and their rates were based on the cost of service. In recent years, FERC has also been subjected to frequent changes in its leadership. These changes have caused the agency to experience substantial shifts in policy direction and priorities, which may have directly affected its progress in developing a new regulatory approach.

[8] The PJM ISO uses the presence of congestion on the transmission lines to determine that, during the period of congestion, competition is reduced and market-based bids or offerings of electricity for sale should be replaced by cost-based bids. In contrast, the New York ISO looks directly at bidding behavior and resulting price effects to determine if market power exists that warrants mitigation.

Transition to Competitive Markets Has Been Occurring Without Substantial Changes to FERC's Regulatory and Oversight Authorities

To some extent, FERC's lack of specific legislative authority for competitive energy markets, and especially for electricity markets, may have delayed development of its new regulatory approach. This is because FERC derives much of its legislative authority, for electricity, from mandates that were enacted almost 75 years ago, when the industry was structured as a regulated monopoly and rates were based on the cost of service. As a result, FERC has had to force fit changes that it would like to accomplish within the framework of these outdated statutes. This has led market participants to contest FERC's legal authority to direct change in these industries.

For example, in Order 888, FERC invoked its authority under section 206 of the Federal Power Act when it ordered "functional unbundling" of wholesale generation and transmission services, imposed a similar open access requirement on unbundled retail transmissions in interstate commerce, and declined to extend the open access requirement to the transmission component of bundled retail sales. Market participants, however, challenged FERC's authority to order these changes. In response to a number of review petitions, in 2001, the District of Columbia Circuit Court upheld most of FERC's jurisdiction to issue Order 888.[9] That decision was appealed in the Supreme Court. Last year the Court agreed to hear argument on two issues: FERC's jurisdiction over unbundled retail transmissions and its refusal to assert jurisdiction over bundled retail transmissions.[10] The Supreme Court agreed with FERC on both issues. Specifically, the Court stated that because the Federal Power Act unambiguously gives FERC jurisdiction over the "transmission of electric energy in interstate commerce," without regard to whether the transmissions are sold to a reseller or directly to a consumer, FERC's exercise of this power is valid. Similarly, FERC's decision not to regulate bundled retail transmissions was accepted as a statutorily permissible policy choice by the Supreme Court.

FERC's efforts to guide or direct restructuring of the electricity industry without legislation explicitly mandating the change have also resulted in debate, within and outside the agency, about its specific authorities over these new competitive markets. In some instances, this uncertainty may have contributed to FERC's hesitation in clearly defining how it would apply its authorities to the emerging electricity markets. An example of

[9] *TAPS v. FERC*, 225 F.3d 667 (D.C. Cir. 2000).

[10] *New York v. FERC*, 535 U.S. 1 (2002).

this is FERC's recent attempts to create RTOs. Questions about FERC's authority to require the formation of RTOs led the agency to initially make participation in RTOs voluntary, as it had done in the past for ISOs. Despite outreach efforts to convince the industry about the advantages of participating in RTOs, FERC made little progress in getting RTOs formed. Although its legislative authorities did not change, FERC recently determined that it did have adequate authority to require RTO formation, and there was a significant policy shift within the agency to require participation in RTOs by the industry. Industry participants not joining an RTO now have to prove to FERC why doing so would harm them. Although the Chairman of FERC believes that the agency has the general authority to take this new course of action, he has stated that it would be helpful if the Congress gave FERC the explicit authority to create RTOs.

Moreover, some of FERC's legislative authorities with regard to refunds of excessive rates and penalties for violations of market rules may not be adequate for regulating in a competitive environment, where there is greater potential for market power abuse. Under its current legislative framework, FERC is limited by the extent to which it can order refunds, and it does not have adequate authority to levy meaningful penalties for market violations. As a result, it is difficult for FERC to curb and respond effectively and firmly to anticompetitive behavior, particularly for electricity markets. For example, under sections 205 and 206 of the Federal Power Act, FERC has the authority to review whether new or existing electricity rates filed with the agency are just and reasonable. If an existing rate is found to be unjust or unreasonable, FERC may set a new rate and may order a refund for the amount charged in excess of the just and reasonable rate. However, refunds may only be ordered for the period following the refund "effective" date. The earliest the refund effective date can be is 60 days after a complaint is filed with FERC or after a notice of Commission-initiated investigation is issued. As a result, this limitation provides no remedy for instances where market participants have charged unjust or unreasonable rates during the period before the refund effective date. In addition, under the Natural Gas Act, FERC is even more limited in ordering refunds than it is under the Federal Power Act. For example, under section 5 of the Natural Gas Act, FERC cannot set a refund effective date but can only change rates prospectively from the date that the Commission finds an existing rate to be unjust and unreasonable.

In addition, FERC does not have a meaningful range of penalties to levy against violators of energy market rules. The Federal Power Act provides FERC with the authority to assess civil penalties for violations of certain regulated activities but not for violation of the just and reasonable rate

requirement. For example, section 31(c) of the Federal Power Act authorizes penalties for violations relating to hydropower generation, and section 316A provides FERC with the authority to levy penalties for violations relating to the transmission of electricity and sales by exempt wholesale generators.[11] No section of the act allows FERC to levy monetary penalties against market participants who charge unjust or unreasonable rates for electricity. Although the Natural Gas Policy Act of 1978 gave FERC some authority to levy civil penalties, this authority applies only to a limited number of natural gas transactions in interstate commerce.

In today's competitive energy markets, the lack of adequate refund and penalty authorities may be a significant handicap to FERC's ability to fulfill its regulatory mandate because market participants have the opportunity to profit by millions of dollars within a very short time through exercising market power and engaging in other anticompetitive behavior. For example, in response to filings made after the recent electricity price spikes in California, FERC determined that it had no authority to order refunds for unjust and unreasonable rates charged prior to the refund effective date. If FERC does not have the authority to curb anticompetitive behavior by ordering refunds or levying meaningful penalties against market violators, the risk of engaging in this type of behavior for market participants is severely diminished. Many FERC officials that we spoke to believe that FERC's credibility as an effective regulator of competitive electricity markets is limited without the authority to levy meaningful penalties. They believe that industry participants do not perceive FERC as a forceful regulator because it does not have adequate "bite" to go after market abusers and therefore cannot deter future violations.

FERC Has Experienced Frequent Leadership Changes as It Has Attempted to Develop a New Approach

Over the past 5 years, FERC has had four different Chairs. Such a high level of leadership turnover may have had a significant impact on the ability of the agency to develop a new regulatory approach for emerging energy markets because the Chair of the Commission also serves as the agency's leader and as the chief administrator of FERC's staff. The Chair, in effect, sets the agency's agenda and controls its strategic plan and outcomes.

[11] 16 U.S.C. 824j, 16 U.S.C. 824k, 16 U.S.C. 824l, 16 U.S.C. 824m.

Our reviews of high-performing public and private sector organizations have shown that fundamental changes in operations and culture can take years to achieve and usually require long-term commitment on the part of agency leaders. When agencies such as FERC experience a high level of turnover in their top leadership, their efforts to effect change are often hampered. For example, the Health Care Financing Administration, which administered the multibillion-dollar Medicare program, had 19 administrators or acting administrators in its 24 years of existence. We found that this high rate of leadership turnover was an inhibiting factor in the implementation of long-term Medicare initiatives and the pursuit of a consistent management strategy for this agency.[12]

Similarly, the lack of continuity in FERC's top leadership may have directly contributed to the agency's lack of progress in developing and implementing a new regulatory approach for competitive energy markets, especially over the last 5 years. Some senior FERC staff told us that the seemingly constant transition caused by recent changes in FERC leadership, coupled with the intense pressure created by the California energy crisis and the bankruptcy of the Enron Corporation, has resulted in a lack of consistent management and direction for the agency. Several agency officials told us that every new Chair brings a different direction to the agency and that when there is a change in the chairmanship, the progress made under a past Chair often becomes irrelevant as everyone's attention shifts to the new Chair's priorities and agenda. Consequently, steps taken to develop a new organizational structure or regulatory approach under a past Chair are often jettisoned, and the staff start the process all over again under the direction of the new leader.

Conclusions

The longer FERC struggles to define and implement an effective approach for the emerging energy markets, the longer these markets will continue to develop and operate without adequate oversight and, potentially, without adequate regulation. At the current time, FERC is not adequately performing the oversight that is needed to ensure that the prices produced by these markets are just and reasonable and therefore, it is not fulfilling its regulatory mandate. While FERC has taken some tentative steps in the right direction, more decisive action must be taken to define and

[12] U.S. General Accounting Office, *Major Management Challenges and Program Risks: Department of Health and Human Services*, GAO-01-247 (Washington, D.C.: January 1, 2001).

implement an effective regulatory and oversight approach. To accomplish the mammoth undertaking posed by the rapidly evolving and increasingly complex energy markets, FERC will have to place the highest priority on developing its oversight function and devote significant management attention and adequate resources to this task.

FERC has not yet developed a detailed oversight approach for competitive energy markets. Market participants need this specificity if they are to view FERC as an effective market monitor and regulator. Although FERC has recently revised its strategic plan to place more emphasis on its oversight of competitive energy markets, the plan still lacks specifics about how the agency will monitor these markets. The revised plan does not include outcome measures for its goals and objectives so that the agency's progress in achieving them can be assessed. The plan also does not clearly and explicitly state how FERC will work with market participants to comprehensively oversee the markets. For example, it appears that FERC plans to rely on the RTOs' MMUs to serve as its frontline for monitoring wholesale electricity markets. The agency, however, has not yet set out expectations for how these units will monitor the markets and how FERC will evaluate their effectiveness.

Moreover, FERC needs to recognize that a new regulatory and oversight approach will require both interim and long-term measures. The agency cannot continue its current policy of waiting for the market structures to be fully in place before developing monitoring actions. For example, FERC does not have the luxury to wait for the RTO structures to be in place, which may take several more years, before detailed monitoring of the markets begins. As the California energy crisis has made adequately clear, FERC simply cannot let the markets continue to go unmonitored for this length of time. Nonetheless, FERC does not have an action plan for oversight of the markets for the interim period before the RTOs' market monitoring units are functioning and the agency can put a comprehensive market oversight approach into place.

Finally, FERC's difficulties in developing and implementing a comprehensive regulatory and oversight approach for competitive energy markets can be attributed, at least in part, to its attempts to help create and to regulate and oversee these markets without explicit direction and guidance from the Congress as to the agency's appropriate role in these markets. FERC has been attempting to design a regulatory and oversight approach for these markets around legal authorities, such as those for ordering refunds and assessing penalties, which were generally enacted when the natural gas and electric industries were subject to cost-of-service

regulation. As part of its current debate in formulating the Energy Policy Act of 2002, the Congress has started to review FERC's legislative framework.

Recommendations for Executive Action

To help ensure that FERC can effectively carry out its responsibilities for overseeing interstate wholesale natural gas and electricity markets, we recommend that the Chairman, FERC, take the following actions:

- Update the agency's strategic plan to include outcome measures that can be used to assess how well FERC is doing in achieving its strategic goals and objectives for overseeing competitive energy markets. This plan should also include specific strategies for achieving the goals and objectives that set out explicitly how FERC will work with market participants to provide comprehensive oversight of the markets. Because of their significant role in FERC's oversight approach, the plan should set out clear expectations for how transmission organizations will monitor energy markets and how FERC will evaluate the effectiveness of their MMUs. These expectations should be made part of FERC's approval of these transmission organizations.

- Develop an action plan for overseeing energy markets, in particular for electricity, until the transmission organizations' market monitoring units become fully operational and FERC can implement a comprehensive oversight approach for these markets. In developing the action plan, FERC should examine how it can use the bulk power studies and the data sources currently available through the MOR room as more effective market monitoring tools.

Matters for Congressional Consideration

To help ensure that FERC can effectively carry out its oversight role with respect to energy markets, the Congress may wish to convene public hearings to review FERC's authorizing legislation and determine, in consultation with FERC Commissioners, whether FERC's authorities need to be revised in light of the changing energy markets. In addition, to help FERC deter improper market behavior, the Congress may want to consider providing FERC with the appropriate range of authorities to levy civil penalties against market participants that engage in anticompetitive behavior and violate market rules.

Agency Comments

In its written comments on a draft of this report, FERC agreed that it had not yet done all that it could to oversee energy markets. The agency stated that, despite a long-standing recognition that it needed to develop the

information, procedures, and staffing to oversee energy markets, it had not previously focused its efforts clearly enough to succeed. According to FERC, this situation is now changing with the launching, in January 2002, of the new Office of Market Oversight and Investigation to oversee and assess the fair and efficient operations of electric and natural gas markets. The new office, according to FERC, will be up and running in August 2002. FERC stated that the office's job will be to understand energy markets and risk management, measure market performance and analyze market data with an eye to recommending market improvements, investigating compliance violations, and, where necessary, pursuing enforcement actions. FERC also stated that the office will report to the Chairman and other Commissioners, bring together all of the staff devoted to oversight and enforcement in one place, and receive the resources it needs to restore and maintain the integrity of the nation's energy markets. FERC further stated that the agency has developed preliminary plans on how the office will work, including a draft mission and function statement, an organizational design, and a comprehensive list of the services and products the office will provide.

We are encouraged and hopeful that FERC's creation of this new office will provide the focus needed to succeed where prior efforts, as described in our report, have not. However, we do not believe that a reorganization alone will be enough to bring about the fundamental changes needed in FERC's regulation and oversight of energy markets. Sustained leadership and top management attention will be necessary to guide and direct the agency through these changes. Many details of the new office's operations are yet to be worked out, and FERC still needs to overcome significant challenges to provide the office with the information, tools, and staff with the skills and knowledge to effectively oversee competitive energy markets.

FERC also agreed with our conclusion that its ability to develop, regulate, and oversee competitive energy markets could be enhanced with new statutory authority and guidance from the Congress on the agency's appropriate role in these markets. FERC agreed that it has often struggled to find market solutions while operating under legislative authority designed for regulated monopolies with cost-of-service rates. The agency noted that additional statutory authority is needed, particularly in providing FERC with the ability to assess civil penalties for violations of the law or FERC rules. FERC further said that the Congress could strengthen the agency's ability to create competitive wholesale energy markets by clarifying the Commission's authority to order the formation of

RTOs. As pointed out in our report, FERC has currently approved the formation of only one RTO.

Separately from its written comments, FERC provided us with some technical changes, which we incorporated into the report where appropriate. FERC's written comments are presented in appendix III.

Chapter 3: FERC Faces Significant Management Challenges to Effectively Monitor Competitive Energy Markets

As FERC develops a new regulatory approach to respond to the restructured energy industry, it will have to overcome significant human capital and organizational challenges. FERC's workforce, which was largely recruited and trained for cost-of-service regulation, currently lacks the knowledge and mix of skills needed to effectively regulate and oversee competitive markets. Although FERC has taken steps to train its current staff and recruit new staff, it has made limited progress in adapting its workforce to the new regulatory environment. In addition, FERC has not fully explored all the personnel tools and flexibilities—such as establishing special pay rates—that are available to federal agencies for responding to workforce recruitment and retention challenges. FERC also has not conducted systematic strategic human capital planning to recruit, develop, train, and retain the type of workforce that can effectively regulate and oversee competitive energy markets. Moreover, FERC's current organizational structure diffuses its market monitoring responsibilities and does not provide the focus and attention that this function needs in the changing regulatory environment.

FERC Has Taken Some Steps to Address Its Human Capital Needs, but Significant Challenges Remain

FERC has been unable to adapt its workforce to meet the challenges of the new competitive markets. Its current staff skill mix is inadequate and training of current staff and recruitment of new staff have not yet occurred at a level that would alleviate gaps in the staff's skill mix. In addition, many experienced and highly trained FERC staff will soon be eligible for retirement and could depart from the agency over the next 3 years. While these retirements provide FERC the opportunity to bring in new staff to fill gaps in its skill mix, the departures will also result in the loss of traditional skills and knowledge that the agency continues to need. Although FERC management has been aware of these issues and has taken some steps to address them, its progress has been limited. Moreover, FERC has not fully explored the use of all the personnel tools and flexibilities available to federal agencies to help them attract, motivate, and retain employees, and FERC has not performed the systematic and comprehensive planning that is needed to resolve its human capital challenges.

FERC Faces Daunting Human Capital Challenges

FERC's current workforce will need to undergo a substantial and rapid transformation if it is to effectively meet the challenges of regulating and overseeing competitive energy markets. Historically, FERC staff operated in a highly regulated environment, setting rates for wholesale electricity sales based on a utility's cost to provide the service. The competencies required to perform this task are markedly different from the

competencies needed to effectively monitor dynamic energy markets. For example, to perform cost-of-service rate setting, FERC traditionally employed staff with knowledge and skills in finance, economics, engineering, and the operations of regulated industries. However, to support its responsibilities for regulating and monitoring competitive markets, correcting anticompetitive situations, and promoting fair and open competition, the Commission needs employees with knowledge and skills in the collection and analysis of market data; information technology; and market operations, including expertise in market rules and structures, competitive pricing, commodity trading, and risk management. According to senior FERC officials, the agency lacks adequate numbers of staff with these competencies and has had trouble attracting and retaining such staff. Energy market participants and state regulators told us that they are also concerned that FERC staff do not have the depth of knowledge and understanding of competitive markets that are needed to effectively regulate and oversee the evolving energy industry. For example, one former FERC Commissioner now working in the energy industry said the skills of FERC staff have fallen behind those of the companies that they regulate. Additionally, many of the state regulatory bodies that we surveyed expressed a lack of confidence in FERC staff's ability to fully understand the complexities of the markets it regulates.

In an effort to increase its staff's knowledge of energy market issues, FERC has been providing additional training opportunities. For example, FERC more than doubled the training budget for the Office of Markets, Tariffs and Rates (OMTR) from fiscal year 2000 to fiscal year 2001 and has used contractors to provide staff training on market-related subjects, such as derivatives. Despite this increased emphasis on training, the general feeling among the staff that we surveyed in OMTR and the Office of the General Counsel is that additional, focused training is needed. Our survey found that over 80 percent of FERC employees responsible for regulating and overseeing energy markets expressed a need for more training in market functions and market structures—in particular, they need a better understanding of how financial markets interact with energy markets and of such issues as trading, hedging, derivatives, and financial instruments. In addition, over half of these staff stated that additional training in basic economic principles and definitions, economic theory and models, and regulatory theory would help them perform their duties (see table 3).

Table 3: Percentage of FERC Staff Indicating That Additional Training Would Help Them Better Monitor and Regulate Energy Markets, by Type of Training

Type of training	Additional training would assist me	Already proficient in this area	Does not apply or no basis to judge
How financial markets interact with energy markets (including trading, hedging, derivatives, and financial instruments)	86%	3%	11%
Market structures	84	9	7
Market functions	81	12	7
Economic theory/models	60	25	16
Regulatory theory	55	40	6
Basic economic principles/definitions	52	39	9
Statistical software packages	41	7	52

Note: Some rows do not total 100 percent because of rounding.

Source: GAO's survey of FERC employees.

FERC has also tried to fill the gaps in its workforce skills by recruiting new employees. However, it has been largely unsuccessful in recruiting and retaining the highly skilled staff it needs. For example, over the last 2 years, FERC has tried to fill a total of 49 nonadministrative positions in OMTR. However, FERC was only able to fill 25, or 51 percent, of these 49 positions, and of the positions filled, the majority represented reassignments of employees within FERC. There were only 10 new hires from outside the agency. Most of these were at the GS-11 level or lower. Several higher level positions remained unfilled.

According to FERC officials and energy industry experts, the Commission is unable to recruit the qualified employees it needs mainly because of the significant difference between government pay scales and compensation in the private sector. Consequently, FERC has historically had trouble getting qualified individuals to apply for jobs and subsequently hiring them into key market regulation and oversight positions at the mid- and upper levels. For example, in fiscal year 2001, FERC advertised an "Energy Industry Analyst–(Energy Trader)" position at the GS-15, step 10, level, which is the highest pay grade and step level available under civil service rules and currently pays about $120,000. The position was first listed from October 31 to November 30, 2000, but garnered only three applicants meeting initial qualifications, and FERC hiring officials did not find any of these applicants suitable to meet the agency's needs. When the position was re-listed from December 11, 2000, to January 11, 2001, only one

qualified person applied, who was also considered unsuitable for the agency's needs. After listing the position a third time from January 22 to February 20, 2001, advertising heavily in key markets such as Houston, New York, and Washington, D.C., and accepting electronic applications, FERC received information from 16 qualified applicants. However, as of February 12, 2002, the position remained unfilled because, according to FERC's human resource staff, after the interview process the hiring officials determined that none of the interviewed applicants met the needs of the position. This example clearly illustrates the difficulty that FERC has had in hiring people with "real world" experience in competitive energy markets, particularly former energy traders.

To help address its recruitment challenges, FERC has started various initiatives to enhance entry-level recruitment. One such initiative is FERC's summer intern program, which began in fiscal year 2001. Of a total of 27 interns who participated in the program, 5 were offered permanent positions and 4 had accepted as of February 2002. FERC plans to expand participation in the program to 40 interns and increase to 12 the number of interns hired into permanent positions for fiscal year 2003. While these positions will help build a future FERC workforce, they do not address the immediate and compelling need that the agency has for experienced and trained market regulation and oversight staff at mid- and upper levels.

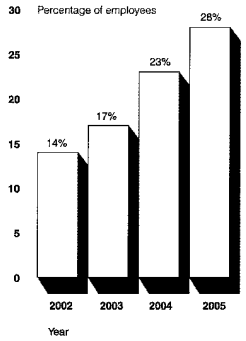
FERC is taking extra steps to retain its newly hired staff by helping them to more quickly become familiar with their duties and responsibilities and the agency's operations. Recently, FERC implemented a mentoring program designed to guide new employees in their career development and enable them to more quickly gain institutional knowledge from more experienced staff. Additionally, new employees in several offices participate in a series of orientation sessions, offered first by human resources staff and later by their program office. These sessions help new employees understand how FERC functions, what its regulatory priorities are, and what is expected of them.

FERC is also challenged in retaining its highly skilled and experienced employees. Although FERC has an overall low rate of attrition (an average of 7 percent per year since 1995), some managers said that key employees are leaving to join private sector energy firms. They said that FERC employees are attractive to the industry because of their knowledge of the regulatory process. In fiscal years 2000 and 2001, OMTR had 15 separations, 13 of which were in upper level positions; of these, 7 staff listed "taking a job in the private sector" as the reason for their resignation. Of the remaining six employees, three said that they were

relocating or transferring to other federal agencies, and three did not give a reason for leaving.

Another human capital challenge for FERC is the impending retirement of a large portion of its staff (see fig. 5). Over one-quarter of FERC's employees will be eligible for retirement by 2005. Many of the employees who will be eligible to retire by 2005 have 20 years or more of government service; are highly educated and trained; and are knowledgeable about the Commission's policies, procedures, and workload. While the departure of so many staff creates opportunities for FERC to realign its workforce skills to better match its needs for the future, it also poses a significant loss of institutional knowledge. FERC has to fulfill a dual responsibility: It must monitor the emerging competitive energy markets while it continues to provide traditional cost-of-service regulation for those areas of the country that are not undergoing energy industry restructuring. According to FERC, this en masse departure of highly qualified and experienced staff may adversely affect the agency's ability to continue to perform high-quality traditional regulatory work.

Figure 5: Percentage of Employees in Mainstream Occupations Eligible to Retire in Fiscal Years 2002-2005



Source: FERC.

Note: Chart reflects retirement eligibility of mainstream occupations as categorized by FERC and includes biologists, accountants/auditors, attorneys, energy industry analysts, and engineers. The percentages for any given year reflect staff that became eligible to retire in prior years, as well as those newly eligible in the year listed.

FERC Has Not Explored the Use of All Available Civil Service Flexibilities

All federal agencies, including FERC, have flexibilities and tools available to them to help overcome workforce recruitment and retention issues, including flexibilities and tools that (1) can be initiated by federal agencies on their own, such as the use of signing and retention bonuses and alternative work schedules; (2) require approval from the Office of Personnel Management (OPM) or the Office of Management and Budget (OMB), such as special salary rates; and (3) require legislative approval, such as excepted service positions.[1] Of these special tools, FERC has used recruitment bonuses, retention allowances, tuition reimbursement, and alternative work schedules to help resolve some of its human capital challenges. For example, according to a senior official in FERC's Office of

[1] A handbook entitled *Human Resource Flexibilities and Authorities in the Federal Government* is available from OPM and provides information on the various human resource flexibilities and authorities available to federal agencies.

the General Counsel, FERC has had recent success in offering recruitment bonuses and tuition reimbursement to attract new attorneys. FERC may be able to further expand the use of these flexibilities by reviewing the experiences of other agencies. For example, the State Department is using retention allowances to create incentives for learning. It pays retention allowances ranging from 5 to 15 percent to certain information technology workers who obtain job-related degrees and certifications. OPM reported that after 1 year of operation, these retention allowances have helped to significantly reduce turnover and increase the skills base of the State Department's information technology workforce.

According to FERC's human resource manager, the agency has not yet requested any of the other flexibilities and tools available from OPM, OMB, or the Congress. For example, FERC has not requested OPM approval to establish special pay rates for critical occupations. Special pay rates allow an agency to offer rates that may be higher than basic pay rates for an occupation or group of occupations. These rates can be established nationwide or in specific local areas if it is determined that the government's recruitment or retention efforts would be significantly handicapped without these higher rates. Similarly, FERC has not asked OMB to establish critical pay authority for its staff. This authority can increase the rate of basic pay for a specific position and may be authorized for positions that require extremely high-level expertise in a scientific, technical, professional, or administrative field or one that is critical to the agency's successful accomplishment of an important mission.[2] However, critical pay may be granted only to the extent necessary to recruit or retain an individual exceptionally well qualified for the position.

As a final option, federal agencies may also request legislative approval to create excepted service positions, which are exempt from the provisions of general civil service requirements. However, FERC has not yet fully examined the need for excepted service positions and is still in the early stages of developing the supporting documentation for this authority. Excepted service authority allows agencies to hire staff through a non-competitive selection process and provides greater flexibility in setting compensation rates. Exceptions may be granted for entire agencies, such as the Federal Bureau of Investigation, or for specific positions, such as members of the State Department's Foreign Service. Some agencies, such

[2] This is subject to the limit on aggregate compensation established by 5 U.S.C. 5307 and 5 CFR part 530, subpart B.

as the Internal Revenue Service, have used flexibilities available within the existing personnel system in concert with excepted service authority to better tailor their human capital policies and practices to their needs.[3]

To better determine how to apply these tools and flexibilities to resolve their workforce issues, some agencies have undertaken formal internal assessments. For example, the U.S. Mint's Office of the Chief Financial Officer formed a Human Resources Flexibilities Team and conducted a two-phase study of the various flexibilities and tools available to, and used by, the agency. Phase one of the study included an extensive review of all human capital flexibilities available to the U.S. Mint under existing laws and regulations. Phase two included an analysis of the U.S. Mint's use of these flexibilities and the development of recommendations to agency leadership for increasing the effective use of these flexibilities as recruitment and retention tools. FERC management has yet to conduct such an assessment for the Commission.

FERC Lacks a Plan for Addressing Its Substantial, but Not Unique, Human Capital Challenges

While FERC's human capital problems appear to be overwhelming, they are not unique and are, in fact, quite similar to issues affecting other federal agencies. As we recently reported in our Performance and Accountability Series, serious human capital shortfalls are eroding the ability of many federal agencies, and threatening the ability of others, to economically, efficiently, and effectively perform their missions.[4] Our past work has shown that agencies such as the Department of Defense, the National Aeronautics and Space Administration, and the Nuclear Regulatory Commission are struggling as FERC is to maintain the workforce skills that they need to fulfill their regulatory responsibilities and missions. These struggles are due to problems such as recruiting qualified employees, downsizing, and pending retirements by many current employees. Given the seriousness of the human capital problem facing agencies throughout the federal government, we added this issue to our list of federal programs and operations that are at high risk in 2001.

[3] The Congress, in the Internal Revenue Service (IRS) Restructuring and Reform Act, authorized IRS to establish up to 40 critical pay positions to attract senior managers with special knowledge and skill that IRS would otherwise have been unable to attract. IRS also created a broadbanded personnel classification and pay system to increase its flexibility in rewarding and utilizing managers.

[4] U.S. General Accounting Office, *Performance and Accountability Series: Major Management Challenges and Program Risks: A Governmentwide Perspective*, GAO-01-241 (Washington, D.C.: January 2001).

Some agencies with human capital challenges comparable to FERC's are beginning to take steps to resolve these issues, and an important first step is the development of a comprehensive strategic human capital management plan that is linked to the organization's strategic and business plans. For example, the Air Force Materiel Command (AFMC) has taken steps toward improving its human capital situation by developing comprehensive plans to reshape its workforce and meet its future business needs. In light of this detailed effort, AFMC gained a better understanding of current and potential workforce gaps and was better able to successfully transform its workforce. However, FERC has yet to undertake a systematic strategic human capital management planning process that can help guide its efforts to recruit, develop, train, and retain the type of workforce that can effectively regulate competitive energy markets.

We have also found that high-performing organizations in the public and private sectors identify their current and future human capital needs—including the appropriate number of employees, the key competencies for mission accomplishment, and the appropriate deployment of staff across the organization—and then create strategies for filling any gaps that are identified from this process. Moreover, high-performing agencies aggressively pursue comprehensive succession planning and executive development actions to address the potential loss of leadership continuity, institutional knowledge, and expertise. This kind of systematic planning process is essential to address the breadth and complexity of human capital challenges and succession planning issues that are looming at FERC. Although FERC senior managers have begun to discuss the issue, to date, FERC has not embarked on such systematic planning efforts. The only related analysis that FERC has conducted is its June 2001 Workforce Analysis, prepared in response to a request from OMB (OMB Bulletin 01-07). While this analysis provides both a "snapshot" of FERC's current workforce and some observations on future issues of concern to FERC management, it falls short of the detailed planning and assessment that effective strategic human capital planning entails.

As we have recently reported,[5] many needed improvements in human capital management can be achieved if federal agencies take a more strategic and performance-based approach to managing their workforce.

[5] U.S. General Accounting Office, *Managing For Results: Building on the Momentum for Strategic Human Capital Reform*, GAO-02-528T (Washington, D.C: March 2002).

Such an approach would include performing effective workforce planning, developing performance goals and measures to address workforce challenges, and linking employee performance to results. We recently developed a model of strategic human capital management to help federal agency leaders better manage their organizations' most important asset—their people. The model is designed to help agency leaders effectively use their people and determine how well they integrate human capital considerations into daily decision-making and planning for the program results they seek to achieve.

Because the transition to modern performance management will require changes in management systems and organizational cultures that often take years to implement, it will also require long-term commitment on the part of agency leaders and managers. To accomplish this, agency leaders need to commit their organizations to valuing and investing in their employees, empowering and providing the employees with the tools to do their best, and implementing modern performance management and incentive systems to focus their efforts on achieving agency missions and goals. However, we have found that the lack of continuity in leadership often hampers these efforts at many agencies. As discussed earlier in this report, FERC has had four different Chairs in the past 5 years. This constant change in leadership, coupled with the demands for management attention to resolve other issues such as the California energy crisis, has diverted FERC's attention from aggressively addressing its human capital challenges.

FERC's Organizational Structure Limits Its Effectiveness

FERC's current organizational structure cannot ensure that the emerging energy markets are adequately monitored, because the structure does not give adequate priority and attention to FERC's market monitoring function. At FERC, the market monitoring function is currently assigned to two of the nine divisions within OMTR. These two divisions—Market Development and Market Information—compete for resources and management attention with the other seven, which are mostly responsible for analyzing case filings and applications from the electricity and natural gas industries. This casework has historically been, and continues to be, FERC's principal mechanism for regulating the activities of energy industry participants. FERC is required to complete its work on most of these cases within legislatively set time frames, such as 30 or 60 days. Consequently, casework demands may receive a higher priority than general market monitoring activities.

In addition, having the market monitoring and casework functions within the same office hampers effective communication between FERC's market monitoring staff and industry participants. Under FERC's rules to ensure independence of its process for resolving cases before the agency (known as ex parte rules), staff are prohibited from private discussions with parties involved in a case pending before FERC. However, many companies or organizations (such as ISOs) from which the market monitoring staff need to obtain information are likely to have cases before FERC at any given time. Consequently, the market monitoring staff may be limited in their ability to hold discussions with these companies or organizations, as well as with other FERC staff who may be involved in case resolution. For example, the Director of Market Analysis for the California ISO told us that because of ex parte rules and FERC's organizational structure it was very difficult for her office to communicate directly with FERC's market monitoring staff during the California energy crisis. Instead, she was forced to communicate with FERC staff in other offices and hope that they would accurately relay her concerns to the appropriate parties within the agency. A former Commissioner also noted this barrier, commenting that ex parte concerns hindered information flow at FERC and inhibited the agency's ability to gather market monitoring data.

FERC has recently created a new Office of Market Oversight and Investigation that will report directly to the Chairman and will be staffed by a multidisciplinary team. The functions of the new office will include understanding energy markets and risk management issues, measuring market performance, investigating compliance violations, and analyzing market data. According to FERC, the new office will have a total of about 100 staff. About 50 staff members will be transferred to this new office from OMTR and the Office of the General Counsel. FERC is requesting funding in its fiscal year 2003 budget proposal to hire the other 50 staff members. FERC stated that many functions of the new Office of Market Oversight and Investigation require expertise that is currently limited at the agency. FERC further stated that in order to fulfill its responsibilities, the new office will need to augment the agency's capabilities in several areas, including conducting intensive market investigations and performing sophisticated market information analysis. However, according to a FERC manager, many details about the office and how it will carry out its responsibilities have not yet been determined.

Conclusions

As the energy industry has evolved, the resources and structures that FERC has in place are no longer adequate to fulfill the agency's new

responsibilities for regulating and overseeing competitive markets. The challenge for FERC is further complicated by the fact that while the agency needs to transform its workforce rapidly and revamp its organizational structure decisively to meet the needs of the new energy markets, it must also maintain the ability to fulfill some traditional regulatory responsibilities. Having staff in place with the requisite competencies to regulate and oversee traditional and emerging competitive markets is essential for FERC to be able to detect and head off service disruptions, price spikes, and market abuses similar to those that occurred in California and other parts of the West in 2000 and 2001. While FERC has taken steps to address its organizational challenges by creating a new Office of Market Oversight and Investigation, much remains to be done to address the agency's persistent human capital challenges.

FERC has struggled to recruit and retain highly qualified and experienced employees in order to be able to regulate and oversee evolving competitive energy markets. However, without having explored the full range of personnel tools and flexibilities that could help address these issues, FERC cannot determine which of the available tools may be best suited to help it achieve its staffing goals. Furthermore, without enhanced training, FERC cannot ensure that its staff will have the knowledge and skills required to understand and adequately regulate and oversee the increasingly complex energy markets. Because of the impending loss of institutional knowledge possessed by the large number of staff soon eligible to retire, it is also questionable whether FERC will be able to effectively provide the traditional regulatory work for which the agency is still responsible.

On a broader scale, without a comprehensive and systematic strategic human capital planning process to guide the agency's efforts to recruit, develop, train, and retain staff, FERC will be unable to effectively regulate and oversee competitive markets. Although this type of planning takes a substantial amount of time and commitment from any agency's top leadership and management, without this high level of attention and commitment, FERC will be unable to effectively resolve its human capital problems. Our model of strategic human capital management should prove helpful to FERC as it moves forward in its planning efforts.

Recommendations for Executive Action

To help ensure that FERC has the mix of staff skills and expertise that it needs to effectively carry out its regulatory and oversight responsibilities for emerging competitive energy markets, we recommend that the Chairman, FERC, identify the personnel tools, flexibilities, and strategies, other than those already in use by FERC, available to federal agencies to recruit and retain employees. A formal internal assessment of the effectiveness and applicability of these to FERC, especially for the new Office of Market Oversight and Investigation, should be conducted. On the basis of this analysis, the Chairman should develop an action plan to use the appropriate tools, flexibilities, and strategies to begin to recruit and hire needed expertise. The Chairman should also develop an action plan to identify and target additional training and development opportunities for current staff involved or potentially involved in carrying out FERC's market oversight functions.

In the longer term, we recommend that the Chairman, FERC, develop a comprehensive strategic human capital management plan to guide FERC's efforts to recruit, develop, train, and retain staff knowledgeable in regulating competitive markets. The plan should be linked to FERC's strategic and business plans and should include the following:

- a skills assessment program that would identify gaps in skills currently held by the workforce that are necessary to carry out the agency's evolving regulatory and oversight responsibilities;
- a recruitment and retention initiative, based on priorities for meeting future regulatory and oversight staffing needs, which addresses filling skill gaps in the current workforce;
- a training effort targeted at increasing staff knowledge in the areas of market functions and market structures, so that FERC staff will be better prepared to regulate and oversee competitive energy markets; and
- a comprehensive succession plan for solving challenges posed by the large number of impending retirements within the agency, including reliable projections of the number of eligible staff who may actually retire.

Agency Comments

In its written comments on a draft of this report, FERC stated that the report accurately addresses the human capital challenges that the agency faces. It noted that its staff today is better suited to regulate cost-of-service rates rather than market-based rates. The agency stated that how it replaces the large number of its employees retiring in the near future will

have a profound effect on its future capabilities. FERC also stated that it has made significant progress recently in hiring new employees through an aggressive recruitment program and is focusing on the skill sets needed for market oversight and investigation. The agency further stated that it will explore all the hiring flexibility available to the agency to build a world-class oversight staff, drawing ideas from agencies with similar regulatory responsibilities over complex and rapidly evolving markets. According to FERC, it has already received congressional authorization to hire five new senior positions for market oversight and investigation and has requested congressional authorization for 50 new positions and $5 million in additional funding. FERC said that it is presently reviewing existing budget allocations across the agency for further resources. Finally, FERC stated that the agency has implemented training programs for existing staff and is working to craft more focused training programs to build technical and leadership capabilities. While all of these steps will help FERC address some of its human capital challenges, we believe that it is important for the Commission to have a comprehensive human capital management plan to guide these efforts over the longer term.

Appendix I: FERC's Principal Strategic Goals and Objectives for Energy Markets

Table 4 shows the Federal Energy Regulatory Commission's (FERC) principal goals and objectives relating to its regulation and oversight of energy markets, as contained in the 1997, 2000, and 2001 versions of its strategic plan.

Table 4: FERC's Principal Strategic Goals and Objectives for Energy Markets

Version	Strategic goals	Strategic objectives
1997	Regulate electric transmission and bulk power markets to • foster the growth of efficient, competitive commodity markets and • protect customers from excessive transmission rates and service discrimination. Regulate natural gas pipelines to • ensure that pipeline transportation service supports efficient, competitive commodity markets and • protect consumers from excessive transportation rates and service discrimination.	Efficient, competitive markets: Customers will have more new products and a reasonable range of suppliers from which to choose in both the electric and natural gas industries. Efficient, competitive markets: Natural gas and electric power prices will become more responsive to market conditions—that is, prices will reflect changing supply and demand conditions more clearly and more quickly. Efficient, competitive markets: Natural gas prices within each trading region will tend to converge, except to the extent that there are demonstrable transportation constraints or costs. Wholesale electricity price differences will also tend to narrow. Efficient, competitive markets: It will be less costly, administratively, to transact business on the interstate natural gas transportation grid. Constraining market power: Market participants will have confidence that natural gas markets, electric markets, and all transportation services are working efficiently and fairly and that market participants are not subject to abuses of market power.
2000	Benefit consumers by providing a fair, open, and efficient regulatory foundation for competition.	Increase pricing efficiency. • Promote innovative, efficiently priced services. • Promote reliability by using market pricing to encourage capacity expansion. Nurture competitive market institutions. • Increase transportation system integration through regulatory reform. • Increase transparency of Commission policies and availability of market-related information • Monitor energy markets. Constrain market power. • Detect and respond to all forms of market power. • Use enforcement and litigation as necessary to remedy anti-competitive behavior.

Version	Strategic goals	Strategic objectives
		Resolve disputes quickly and fairly. • Promote informal procedures to resolve issues, especially the use of alternative dispute resolution. • Target litigation for those cases where it makes sense.
2001	Promote a secure, high-quality, environmentally-responsive energy infrastructure through consistent policies.	Remove roadblocks impeding market investment. Provide clarity of cost recovery to infrastructure investors. Proactively address landowner, safety and environmental concerns. Stimulate use of new technology. Promote measures which improve the security and reliability of the energy infrastructure.
	Foster nationwide competitive energy markets as a substitute for traditional regulation.	Advance competitive market institutions across the entire country. Establish balanced, self-enforcing market rules.
	Protect customers and market participants through vigilant and fair oversight of the transitioning energy markets.	Improve our understanding of energy market operations. Assure pro-competitive market structures. Remedy individual market participant behavior as needed to ensure just and reasonable market outcomes.
	Efficiently administer the agency's resources to accomplish the agency's goals.	Attract, train, and retain staff to fulfill the strategic plan. Manage information technology to better serve the public and streamline work processes. Communicate our activities more clearly with customers, elected officials, and industry. Integrate agency business planning and budgeting processes. Build strong partnerships with all stakeholders, particularly with governors and states.

Appendix II: GAO Survey of Current FERC Employees in Selected Offices

This appendix contains the questions and responses from our survey of FERC employees in the Office of Markets, Tariffs and Rates and staff in the Office of the General Counsel's sections for Markets, Tariffs, and Rates and Market Oversight and Enforcement. Responses are expressed as a percentage of those responding to the survey.

United States General Accounting Office

Survey of Federal Energy Regulatory Commission Employees

Introduction

The U.S. General Accounting Office (GAO), an independent agency of Congress, is conducting a review of management issues at the Federal Energy Regulatory Commission (FERC). As part of our study, we are soliciting the views of the FERC staff in the Office of Markets, Tariffs, and Rates and related sections of the Office of General Counsel to obtain their opinions about a variety of topics relating to the work of the FERC.

Most of the questions in this questionnaire can be answered by checking boxes or filling in blanks. Space has been provided at the end of the survey for any additional comments. The survey should take about 30 minutes to complete.

GAO will take steps to prevent the disclosure of individually identified data from this survey. Only GAO staff assigned to this study can access and view your responses. **No one at the FERC will see your individual responses.** The PIN number associated with the survey is included only to allow you to access the survey and enter your responses, and to aid us in our follow-up efforts. Survey results will be reported in summary form. If individual answers are discussed in our report, no information will be included that could be used to identify individual respondents.

If you have any questions, please call Elizabeth Erdmann at (202) 512-8113 or send e-mail to erdmanne@gao.gov.

Your participation is very important and we urge you to complete this survey. We cannot provide meaningful information to the Congress on these issues without your frank and honest answers.

Thank you for your time and assistance.

Please refer to the following definitions when completing this survey:

FERC - Refers to the agency as a whole, not any particular office, division, group, or team, or the Office of General Counsel.

Office - Refers to the Office of Markets, Tariffs, and Rates (OMTR) or the Office of General Counsel (OGC).

Division/Section - Refers to a division within the Office of Markets, Tariffs, and Rates, such as the Division of Tariffs and Rates, the Division of Market Information, or the Division of Market Development or a section within the Office of General Counsel such as Markets, Tariffs, and Rates or Market Oversight and Enforcement.

Group - Refers to the group within a single division of the Office of Markets, Tariffs, and Rates, such as the West Group 1, the Market Development Group, or the Information Analysis Group.

1

BACKGROUND INFORMATION

The objective of this section is to obtain general information about your current position with FERC.

1. How long have you been employed by FERC, including its predecessor, the Federal Power Commission? *(enter number of years. If less than 6 months, enter 0.)*

   Mean = 14.91 years

2. In which division in OMTR or section in OGC do you work now? *(Check one.)*

   43% Division of Tariffs and Rates
   9% Division of Market Development
   6% Division of Market Information
   10% Division of Litigation
   6% Division of Policy, Innovation, and Communication
   3% Office of the Chief Economic Advisor
   3% Division of Issue Identification and Resolution Management
   6% OGC Section of Market Oversight and Enforcement
   14% OGC Section of Markets, Tariffs, and rates

3. In which office did you work before the FERC First reorganization, which occurred in 1998? *(Check one.)*

   36% Office of Electric Power Regulation
   25% Office of Pipeline Regulation
   7% Office of Economic Policy
   3% Office of the Chief Accountant
   2% Office of Enforcement
   13% Office of General Council
   5% Other (please specify)_____

   9% Was not employed by FERC prior to the 1998 reorganization

4. Which of the following generally describes your current area of work? *(Check one.)*

   4% Accountant/Auditor
   8% Economist (Industry, Financial, etc.)
   5% Engineer (Electrical, Mechanical, Petroleum, etc.)
   55% Energy Industry Analyst
   3% Other Analyst (Financial, Budget, Operations Research, Program, etc.)
   2% Information Technology Specialist
   20% Attorney
   3% None of the above (please specify) _____

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ORGANIZATIONAL EFFECTIVENESS

The objective of this section is to obtain information about FERC's effectiveness in meeting its mission, goals, and objectives.

5. In general, how clear or unclear to you are each of the following? *(Check one box in each row.)*

	Very clear (1)	Somewhat clear (2)	Somewhat unclear (3)	Very unclear (4)	No basis to judge
a) **FERC's** overall mission/goals and objectives	40%	45%	9%	5%	2%
b) Your **office's** goals and objectives	31	40	21	7	2
c) Your **division's** goals and objectives	38	34	17	9	2
d) Your **group's** goals and objectives	40	31	14	10	5
e) Your current duties and responsibilities	52	29	13	5	0

6. In general, how effective or ineffective is FERC in doing the following? *(Check one box in each row.)*

	Very effective (1)	Somewhat effective (2)	Neither effective nor ineffective (3)	Somewhat ineffective (4)	Very ineffective (5)	No basis to judge (6)
a) Promoting sufficient electricity supply and delivery (transmission) infrastructure	9%	34%	15%	11%	7%	23%
b) Promoting competition in electricity markets	13	40	10	10	7	19
c) Regulating wholesale electricity transmission in interstate commerce	20	40	8	8	5	19
d) Regulating wholesale electricity sales in interstate commerce	13	42	10	10	6	19
e) Monitoring wholesale electricity markets	5	27	16	16	12	23
f) Promoting sufficient natural gas supply and delivery infrastructure	19	27	11	6	3	35
g) Promoting competition in natural gas markets	21	32	8	4	4	33
h) Regulating interstate natural gas transportation	24	34	6	3	3	30
i) Monitoring natural gas markets	8	24	15	8	7	38
j) Other - Please specify: _____						

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7. More specifically, with regard to regulation and oversight of **wholesale electricity markets**, overall, how effective or ineffective is FERC in doing the following? *(Check one box in each row.)*

	Very effective (1)	Somewhat effective (2)	Neither effective nor ineffective (3)	Somewhat ineffective (4)	Very ineffective (5)	No basis to judge (6)
Cost-of-Service Rates						
a) Establishing just and reasonable cost-of-service wholesale electricity prices	26%	33%	4%	8%	3%	27%
b) Gathering data to establish just and reasonable cost-of-service wholesale electricity prices	21	31	10	8	4	27
c) Analyzing data to establish just and reasonable cost-of-service wholesale electricity prices	24	30	8	7	4	27
Market-Based Rates						
a) Establishing market structure and rules to provide competitive, well-functioning wholesale electricity markets that produce just and reasonable rates	9%	30%	15%	15%	9%	23%
b) Gathering data to determine whether market-based wholesale electricity rates are just and reasonable	6	21	15	19	14	24
c) Analyzing data to determine whether market-based wholesale electricity rates are just and reasonable	5	23	13	17	16	26
Other Market Issues						
a) Detecting market power abuses in wholesale electricity markets	5%	21%	16%	21%	16%	22%
b) Correcting detected market power abuses in wholesale electricity markets	8	27	13	17	14	21
c) Identifying problems concerning wholesale electricity market structure and rules	10	31	13	16	11	19
d) Remedying problems concerning wholesale electricity market structure and rules	7	29	17	17	11	19
e) Resolving complaints and disputes among electricity market participants quickly and fairly	13	36	12	13	6	21
f) Enforcing violations of FERC's requirements relating to wholesale electricity sales	6	26	15	12	10	30
g) Other - Please specify: _____						

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8. More specifically with regard to regulation and oversight of **interstate natural gas transportation**, overall, how effective or ineffective is FERC in doing the following? *(Check one box in each row.)*

	Very effective (1)	Somewhat effective (2)	Neither effective nor ineffective (3)	Somewhat ineffective (4)	Very ineffective (5)	No basis to judge (6)
Cost-of-Service Rates						
a) Establishing just and reasonable cost-of-service natural gas prices	27%	23%	6%	2%	1%	42%
b) Gathering data to establish just and reasonable cost-of-service rates for interstate natural gas transportation	23	26	5	5	1	41
c) Analyzing data to establish just and reasonable cost-of-service natural gas prices	27	23	3	4	1	42
Market-Based Rates						
a) Establishing market structure and rules to provide competitive, well-functioning natural gas markets	16%	32%	7%	4%	3%	38%
b) Gathering data to determine whether market-based rates for interstate natural gas transportation are just and reasonable	9	31	8	6	5	41
c) Analyzing data to determine whether market-based rates for interstate natural gas transportation are just and reasonable	12	27	11	5	5	41
Other Market Issues						
a) Detecting market power abuses in natural gas markets	5%	30%	10%	9%	6%	39%
b) Correcting detected market power abuses through changes in market rules	7	31	9	8	5	40
c) Identifying problems concerning natural gas market structure and rules	10	33	7	9	3	38
d) Remedying problems concerning natural gas market structure and rules	11	33	5	9	4	39
e) Resolving complaints and disputes among natural gas market participants quickly and fairly	16	29	10	3	2	40
f) Enforcing violations of FERC's requirements relating to natural gas transmission	13	28	6	8	4	42
g) Other - Please specify: _____						

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9. Would you agree or disagree with the following statements as they relate to various issues in FERC? *(Check one box in each row.)*

	Strongly agree (1)	Agree (2)	Neither agree nor disagree (3)	Disagree (4)	Strongly disagree (5)	No basis to judge (6)
Teamwork/External Cooperation						
a) Teamwork with others outside my office is encouraged.	24%	43%	16%	12%	5%	0%
b) Teamwork within my office is encouraged.	35	37	15	11	2	0
c) Teamwork within my division/section is encouraged.	42	37	9	11	2	0
d) Coordination and cooperation with state regulators is adequate.	8	23	24	14	5	25
e) Coordination and cooperation with Independent System Operators (ISO's) is adequate.	6	22	18	13	5	36
Management/Resources						
a) FERC top management (the Commissioners and office directors) provides clear and concise direction	5%	33%	21%	24%	15%	2%
b) My immediate managers provide clear and concise direction	25	38	14	15	7	0
c) Top management has clearly defined what role FERC is going to play in monitoring markets.	5	19	24	27	17	8
d) Staffing levels in FERC are satisfactory.	2	20	18	31	21	8
e) The employee skill mix in FERC is adequate.	4	25	18	30	18	6
f) Information technology support and services are satisfactory.	9	43	16	21	12	0
g) My office maintains a strong focus on achieving the agency's mission.	18	37	27	10	5	3
Data/Knowledge Requirements						
a) Staff understands what data are required to effectively monitor and regulate natural gas markets.	5%	29%	13%	15%	6%	32%
b) Staff understands what data are required to effectively monitor and regulate wholesale electricity markets.	4	30	18	24	9	16
c) Staff has adequate access to data on electricity market performance.	3	19	17	27	12	22
d) Staff has adequate access to data on natural gas market performance.	3	25	13	17	4	37
e) Staff has adequate knowledge of, or experience with regulating competitive electricity markets.	5	20	25	21	12	17
f) Staff has adequate knowledge of, or experience with regulating competitive natural gas markets.	8	33	12	11	4	33
g) Staff understands the integration of gas and electrical markets.	6	32	22	20	7	14

Continued

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9.(*Continued)* Would you agree or disagree with the following statements as they relate to various issues in FERC? *(Check one box in each row.)*

	Strongly agree (1)	Agree (2)	Neither agree nor disagree (3)	Disagree (4)	Strongly disagree (5)	No basis to judge (6)
Authority						
a) FERC should have authority over new generation siting.	17%	27%	15%	19%	9%	12%
b) FERC should have authority over electrical transmission line siting.	33	36	9	5	5	12
c) FERC should have authority to enforce reliability rules for electricity.	42	36	9	2	1	10
d) FERC should have additional authority to require submission/sharing of data from ISO's.	45	33	8	2	1	12
e) FERC should have additional authority to levy penalties.	45	38	6	1	0	10

When answering the next question, please recall how we defined division/section earlier in the survey:

Division/Section - Refers to a division within the Office of Markets, Tariffs, and Rates, such as the Division of Tariffs and Rates, the Division of Market Information, or the Division of Market Development or a section within the Office of General Counsel such as Markets, Tariffs, and Rates or Market Oversight and Enforcement.

10. Thinking about your current division in OMTR or section in OGC, would you agree or disagree with the following statements? *(Check one box in each row.)*

	Strongly agree (1)	Agree (2)	Neither agree nor disagree (3)	Disagree (4)	Strongly disagree (5)	No basis to judge (6)
a) My division/section has clearly defined its goals and objectives	17%	38%	20%	18%	8%	0%
b) My division/section has set clear performance expectations	15	34	19	21	10	0
c) My division/section can retain quality employees	10	30	24	23	11	2
d) My division/section currently has adequate staff to do its work	5	25	21	29	16	4
e) My division/section plans for its future staffing needs	4	27	22	11	10	27
f) The staff in my division/section have the skills needed to do their jobs well	12	42	18	20	6	3
g) Managers in my division/section encourage me to attend training	20	41	20	11	6	2
h) Managers in my division/section provide time for me to do attend training	22	43	20	8	4	3

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11. In your opinion, to what extent, if at all, would each of the following help you perform your job duties better? *(Check one box in each row.)*

	To a very great extent (1)	To a great extent (2)	To a moderate extent (3)	To some or little extent (4)	To no extent (5)	No basis to judge (6)
a) More autonomy in carrying out my job responsibilities	7%	17%	27%	23%	23%	3%
b) More direction from management	18	25	27	19	10	2
c) More supervision from management	3	8	21	36	31	2
d) Improved communication between offices	27	29	23	11	5	5
e) Improved communication between divisions in OMTR or sections in OGC	27	26	25	11	5	6
f) Additional training opportunities	15	19	34	19	11	3
g) More "teaming" with those knowledgeable in other subject areas (Please list subject areas) _____	20	19	24	20	15	3
h) Other - Please specify: _____						

12. In your opinion, would additional training in the following subject areas assist you in better monitoring or regulating energy markets? *(Check one box in each row.)*

	Additional training would assist me greatly (1)	Additional training would assist me somewhat (2)	I feel I'm already proficient in this area (3)	Training in this area would not be applicable to the work I do (4)	No basis to judge (6)
a) Basic economic principles/definitions	14%	38%	39%	6%	3%
b) Economic theory/models	14	46	25	12	4
c) Regulatory theory	17	38	40	3	3
d) Market functions	32	49	12	4	3
e) Market structures	33	51	9	4	3
f) Statistical software packages such as SAS or SPSS	11	30	7	35	17
g) Understanding how financial markets interact with energy markets (including trading, hedging, derivatives, and financial instruments).	37	49	3	7	4
h) Other - Please specify: _____					

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MORALE AND WORK ENVIRONMENT

The objective of this section is to obtain your views on morale and the general work environment at FERC.

13. Overall, how would you characterize the current level of morale in your division/section? *(Check one.)*

2% Very high
27% Generally high
30% Neither high nor low
24% Generally low
17% Very low

1% No basis to judge

14. Specifically, how satisfied or dissatisfied are you with each of the following as they relate to your current work environment? *(Check one box in each row.)*

	Very satisfied (1)	Somewhat satisfied (2)	Equally satisfied as dissatisfied (3)	Somewhat dissatisfied (4)	Very dissatisfied (5)	No basis to judge (6)
Communication						
a) Communication between the Chairman and my division/section	10%	26%	20%	11%	7%	26%
b) Communication between the Commissioners (not including the Chairman) and my division in OMTR or section in OGC	6	22	22	14	6	30
c) Communication between my office's top management and my division	12	24	13	15	14	22
d) Communication between different divisions/sections within my office	9	24	20	24	14	9
e) Communication between groups within my division/section	20	29	21	14	10	7
f) Communication with offices other than my own	5	28	24	20	14	11
g) Communication between management of different offices	7	17	19	18	13	28
h) Communication with groups outside FERC	4	21	28	10	10	28
Cooperation						
a) Cooperation between different divisions in OMTR and sections in OGC	7%	29%	18%	25%	11%	10%
b) Cooperation between groups within my division in OMTR or section in OGC	18	34	19	16	5	8
c) Cooperation with offices other than my own	7	29	26	20	7	12
d) Cooperation between management of different offices	8	20	23	15	10	25
e) Cooperation with groups outside of FERC	6	23	25	7	7	31

Continued on next page.

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14. (Continued) Specifically, how satisfied or dissatisfied are you with each of the following as they relate to your current work environment? *(Check one box in each row.)*

	Very satisfied (1)	Somewhat satisfied (2)	Equally satisfied as dissatisfied (3)	Somewhat dissatisfied (4)	Very dissatisfied (5)	No basis to judge (6)
Leadership/Change						
a) Leadership provided by Commissioners and office directors at FERC	9%	32%	20%	21%	12%	6%
b) Leadership/supervision that you directly receive	23	31	17	15	12	2
c) Organizational changes within my office	5	14	22	23	30	6
d) Changes in my job duties as a result of recent reorganization	10	20	29	12	17	12
Training/Staffing						
a) Availability of training opportunities at FERC	21%	42%	22%	8%	5%	2%
b) Staffing level in my division of OMTR or section in OGC	6	28	21	23	14	7
c) Staff skills mix	6	29	26	21	13	5
d) Use of teaming within my office	13	34	26	18	8	2
e) Use of teaming between OMTR and OGC	10	33	19	16	13	10
Other						
a) Availability of resources (i.e., budget, technology, staff, etc.) necessary to do my job at FERC	8%	38%	22%	18%	11%	4%
b) Availability of rewards for job performance in my division of OMTR or section in OGC	11	26	19	20	19	5
c) Other - Please specify: _____						

15. Thinking about the issues covered in the previous question concerning your current work environment, overall, how satisfied or dissatisfied are you with your work environment at FERC? *(Check one.)*

11% Very satisfied
39% Generally satisfied
23% Equally satisfied as dissatisfied
20% Generally dissatisfied
7% Very dissatisfied

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FERC FIRST

The objective of this section is to obtain your views on the FERC First initiative.

16. Were you employed by FERC before the FERC First reorganization, which occurred in 1998? *(Check one.)*

87% Yes ➔ ***Continue with question 17.***

13% No ➔ ***Skip to question 22, Comments.***

17. To what extent, if at all, do you believe that the efforts to implement FERC First improved FERC's ability to effectively monitor or regulate energy markets overall? *(Check one.)*

0% To a very great extent
4% To a great extent
17% To a moderate extent
25% To some or little extent
49% To no extent

6% No basis to judge

18. To what extent, if at all, do you believe that the efforts to implement FERC First have improved your ability to perform your job duties? *(Check one.)*

2% To a very great extent
4% To a great extent
12% To a moderate extent
17% To some or little extent
63% To no extent

1% No basis to judge

19. Prior to the FERC First reorganization, which of the following was your area of primary focus? *(Check one.)*

42% Gas
49% Electricity
9% Other - Please specify: _____

20. After the FERC First reorganization, which of the following is your area of primary focus? *(Check one.)*

17% Gas
38% Electricity
39% Both gas and electricity
6% Other - Please specify: _____

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21. In your opinion, to what extent, if at all, has your work focus changed as a result of the FERC First reorganization? *(Check one.)*

15% Changed to a very great extent
15% Changed to a great extent
24% Changed to a moderate extent
24% Changed to little or some extent
24% Has not changed at all

Please explain your response_____

COMMENTS

22. If you have any additional comments relating to any of the issues raised in this questionnaire, please enter them in the space provided.

23. If you have any additional suggestions not noted elsewhere on this questionnaire about how FERC, OMTR or OGC can improve operations, please enter them in the space provided.

Thank you for your assistance.

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Appendix III: Comments from the Federal Energy Regulatory Commission

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF THE CHAIRMAN

May 31, 2002

Mr. Jim Wells
Director, Natural Resources and Environment
United States General Accounting Office
Room 2T23
441 G Street, NW
Washington, DC 20548

Dear Mr. Wells:

Thank you for your letter of May 16, 2002, enclosing your draft report of *Energy Markets: Concerted Actions Needed by FERC to Confront Challenges That Impede Effective Oversight.* I appreciate the opportunity to comment on this report and congratulate you on your effort.

In general, I agree with the conclusions of your report. The Commission's internal restructuring to support its new market oversight role has not kept pace with the speed of energy industry restructuring. Your recommendations of how to meet the challenges that lay ahead are consistent with our current direction. Since I became Chairman in September 2001, the Commission has taken aggressive measures to address the key challenges we face - *ensuring adequate infrastructure* for our Nation's energy industries; fostering nationwide *competitive energy markets with balanced rules;* and developing *vigilant market oversight* to ensure that energy markets are competitive, efficient, and fair. I appreciate this opportunity to suggest that our current efforts are paying off, and we have a plan that is ready to implement the additional resources and statutory authority that have been identified in this report.

I agree with your report's conclusion that we have not yet done all we can to oversee energy markets. Despite a long-standing recognition that we needed to develop the information, procedures and staffing to oversee markets, as of the time of your assessment, the Commission had not previously focused its efforts clearly enough to succeed. That has now changed. In January 2002 we launched a new Office of Market Oversight and Investigation (OMOI) to oversee and assess the fair and efficient

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operations of electric power and natural gas markets. The new office, under the leadership of its first director, William Hederman, will be up and running in August, 2002. Its job will be to understand energy markets and risk management, measure market performance and analyze market data with an eye to recommending market improvements, investigate compliance violations, and, where necessary, pursue enforcement actions. The office:

- will report directly to me and my fellow commissioners,
- will bring together all of the staff devoted to oversight and enforcement in one place, and
- will receive the resources it needs to restore and maintain the integrity of our nation's energy markets.

Your report accurately addresses the human capital challenges that we face. Today's staff is better suited to regulate cost-of-service rates than market-based regulation. By 2005 one quarter of our employees will be eligible to retire and half will be eligible for early out retirement. How the Commission replaces these employees will have a profound effect on the future capabilities of the agency. We have made significant progress recently in hiring new employees through an aggressive recruitment program. We are focusing on the skill sets we need for market oversight and investigation, and we will explore all the hiring flexibility available to us to build a world-class oversight staff, drawing ideas from agencies with similar regulatory responsibilities over complex and rapidly evolving markets. We have already received Congressional authorization to hire five new senior positions for market oversight and investigation and I have requested Congressional authorization for 50 new positions and $5 million in additional funding. We are presently reviewing existing budget allocations across the agency for further resources. Finally, we have implemented training programs for existing staff and are working to craft more focused training programs to build technical and leadership capabilities.

I agree with your report's conclusion that the Commission's ability to develop, regulate and oversee competitive energy markets could be enhanced with new statutory authority and guidance from Congress on the agency's appropriate role in these markets. As your report indicates, the Commission has often struggled to find market solutions while operating under legislative authority designed for regulated monopolies with cost-of-service rates. Additional statutory authority is needed, particularly in providing the Commission with the ability to assess administrative penalties for violations of the law or Commission rules. Congress could also strengthen the Commission's ability to create competitive wholesale markets by clarifying the Commission's authority to order the formation of RTOs.

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I have enclosed a summary of the Commission's current efforts to address issues of market oversight, human capital and legislative authority.

Thank you for your insight and recommendations on how we can improve our efforts to regulate and oversee electricity, natural gas and oil pipeline markets. I appreciate the hard work your staff put into this report and hope it will enable us to obtain the resources and authority needed to face the challenges before us. Thank you again for the opportunity to comment on your report.

Best regards,

Pat Wood, III
Chairman

Enclosure

Attachment: Recent FERC Market Oversight Initiatives

Our current Strategic Plan, adopted on September 26, 2001, explicitly recognizes the need to provide vigilant, fair oversight of energy markets as one of the three major substantive challenges we face in the next decade. The past two years have made it abundantly clear that emerging energy markets can be subject to both abusive actions by individual companies and more general system dysfunctions. The agency must recognize such problems rapidly and respond to them quickly and cogently to make wholesale markets work for the Nation's energy customers.

Following the Strategic Plan, in January 2002 we created a new Office of Market Oversight and Investigation to meet the challenge. This Office represents a fundamental break with the past. It will:

- Concentrate all of our oversight and investigation functions in one place. This will avoid the diffusion of effort that the GAO report observes as one of the problems of the past.
- Report directly to the Chairman and provide information directly to all of the Commissioners on a regularly scheduled timetable. This status provides for executive leadership and regular input into the thinking of our decision-makers.
- Have the resources it needs to do the job. We have requested $5 million, 50 full-time equivalents, and the authority to hire 5 new senior (SES or SL) staff for market oversight in our FY 2003 budget. We have already hired an expert in the energy and financial industries to set up and run the new office.

The new Office will be operational in August 2002. We have developed preliminary versions of how it will work: a mission and function statement, an organizational design and a comprehensive list of the services and products the Office will produce. These plans are attached. In light of various findings in the GAO report, three aspects of the new Office's products deserve highlighting. It explicitly includes:

- Monitoring of markets in regions where no market monitors are in place at Regional Transmission Organizations (RTOs) or Independent System Operators (ISOs), and working closely with market monitors of RTOs and ISOs where they do exist.
- Providing advance warnings of problems that can be anticipated and timely responses to those that cannot.

- Developing and publishing market performance measures as a key product in the overall market oversight program. These measures will be a major part of the Commission's overall performance measures submitted to Congress every year. Unsatisfactory performance will also be traced to its root cause, either market design rules, structural features of supply and/or demand, market participant behavior, to inform corrective policy action.

OMOI will greatly improve our ability to oversee and investigate markets. However, we have already made significant progress within our old structures. Within the past year, our staff:

- Produced and reported studies on infrastructure and transmission constraints in all regions of the United States,
- Improved its daily and monthly reporting to the Commission,
- Responded to a large array of special needs for market analysis for various Commission proceedings and investigations,
- Increased its access to needed data from industry organizations, RTOs, and individual companies, and
- Hired 7 new staff in the markets program area with 9 additional job offers or start dates pending,
- Targeted recruitment efforts to needed skill sets, leading to the posting of 10 vacancy announcements above entry level with 230 applications for these positions including many promising candidates.

A key purpose of market oversight is to identify market problems and propose remedies. Here, too, we are making progress even before OMOI is established. We saw that inconsistent electric market designs create unnecessary transactions costs and market designs that fail to recognize realities of the electric grid create opportunities for market manipulation. In response, we will issue a proposed rule this summer on standard market design (SMD) that will standardize a thorough set of market rules. We saw that non-discriminatory and rapid generator interconnection is critical to competition and providing adequate infrastructure. In response we issued a proposed rule this spring to standardize interconnection agreements. We saw that poor information on market conditions leads to illiquid markets and reduced trust in the integrity of the market. In response we issued Order No. 2001 requiring the public reporting of pricing and other terms of transactions.

These measures will both greatly reduce the risk of market dysfunction and make market monitoring a much stronger part of overall market institutions. Still, the experience of the last two years shows that no set of initial plans will be perfect. Our aim is to use new rules to *make markets work* - and to use market oversight and investigation to *make sure that markets work.*

Resources

As the GAO report finds, past Commissions had limited success hiring staff at the mid- and upper levels with knowledge of and experience with competitive energy markets. Our recent targeted recruiting efforts have generated much greater interest by more promising candidates than in past efforts, providing reason for optimism. We will continue to be more creative in our approaches to hiring and retaining needed staff and offering wages that are competitive with the private sector. Language in the Commission's current FY 2002 budget appropriation provides additional resources and SES/SL positions for this purpose. Since last November, the Commission has been working with the Office of Personnel Management to gain approval for these positions and will continue to do so. I also support legislation to provide the Commission with additional recruitment and pay flexibilities, and with exemptions from parts of Title 5 or, in the alternative, a demonstration project through OPM. Given the national importance of making energy markets work well, OMOI will also appeal directly to the civic-mindedness of experts in the relevant disciplines who would be willing to make some financial sacrifice to serve the public interest.

Need for Greater Statutory Authority

As the report notes, the Commission has often struggled to find market solutions while operating under legislative authority designed for regulated monopolies with cost of service rates. Additional statutory authority is needed in the following areas.

Congress can help the Commission protect customers against the exercise of market power by amending the Federal Power Act to allow the Commission to establish a refund effective date that is as early as the date a complaint is filed or initiated by the Commission. The Commission relies on Section 206(b) of the Federal Power Act for refund protections if it finds that market-based rates are no longer just and reasonable. Section 206(b) provides that whenever the Commission institutes a Section 206 investigation of a rate or charge that may be unjust or unreasonable, the Commission must establish a refund effective date. If the investigation is based on a complaint, the refund effective date must be no earlier than 60 days after the complaint is filed or initiated by the Commission. Permitting the Commission to set a refund effective date as of the date a complaint is filed will increase the deterrent effect of refunds by extending the time period of possible refunds and give customers a stronger incentive to notify the Commission immediately when they perceive manipulation of the electricity markets because customers will have access to greater refunds.

Congress can also increase civil and criminal penalties under the Federal Power Act (FPA) and Natural Gas Act (NGA). These changes will provide stronger deterrents

to anticompetitive behavior, market manipulation, and other violations of the FPA and NGA. Currently, FPA section 316A provides for a civil penalty authority of up to $10,000 per day for violations of Section 211, 212, 213 or 214. These penalties could be broadened to all sections of the FPA and increased significantly. The NGA contains no provision to allow the Commission to level civil penalties. The Commission supports a recent White House proposal to increase the penalty for willful and knowing violation of the FPA from the current $5,000 level to $1 million and that the potential prison term be increased from two to five years. For a violation of the Commission's regulations under the FPA, the White House proposed to increase the penalty from $500 per day to $25,000 per day. A similar provision could be added to the NGA.

Finally, Congress can help by clarifying the Commission's jurisdiction with regard to RTOs. Since RTOs help solve many of the problems observed in recent experience, Congress should clarify the Commission's authority to require RTO membership.

OFFICE OF MARKET OVERSIGHT AND INVESTIGATIONS

Vision

Vigilant oversight and vigorous enforcement of proper market rules ensure dependable, affordable, competitive energy markets to benefit end use customers and other participants.

Mission

Guide the evolution and operation of energy markets to ensure effective regulation and protect customers through understanding markets and their regulation, timely identification and remediation of market problems, and assured compliance with Commission rules and regulations.

Functions

Assess market performance through:

- analyzing market structures and proposing policies for improvement;
- acquiring and analyzing public and proprietary information data bases;
- conducting market research and developing market models and simulations;
- analyzing effects of current and proposed regulations, market rules and policy options; and
- advising the Commission on the market effects of current and proposed policies.

Ensure conformance with Commission rules through:

- auditing compliance with Commission rules and reporting requirements;
- investigating actions of market participants;
- facilitating resolution of disputes among market participants and regulated entities; and
- enforcing Commission rules that govern the markets.

Produce internal and external reports:

- describing the state of energy markets;
- reviewing and analyzing market occurrences and trends;
- providing early warning of vulnerable market conditions; and
- making recommendations on the functioning and governance of energy markets.

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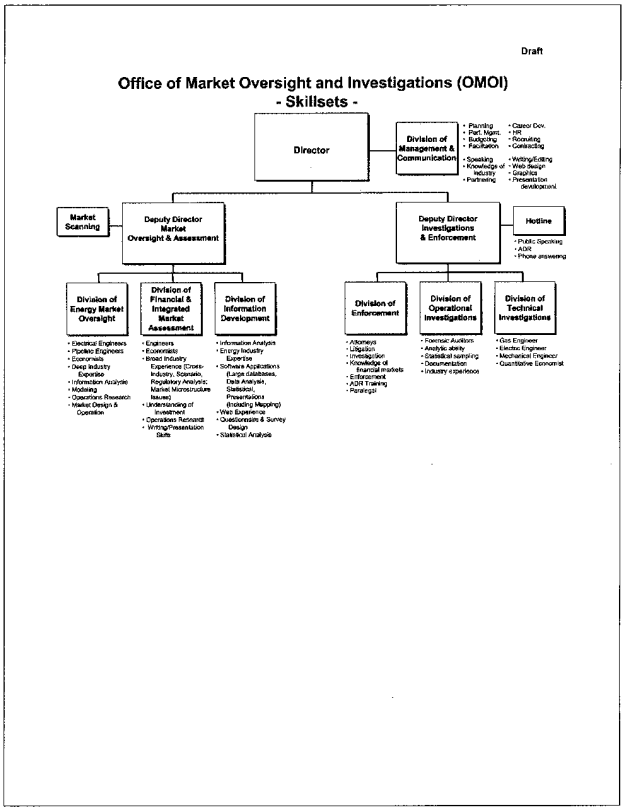
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Office of Market Oversight and Investigations (OMOI)
- Skillsets -
Director
Division of Management & Communication
• Planning
• Perf. Mgmt.
• Budgeting
• Facilitation
• Speaking
• Knowledge of Industry
• Partnering
• Career Dev.
• HR
• Recruiting
• Contracting
• Writing/Editing
• Web Design
• Graphics
• Presentation (evaluations)
Market Scanning
Deputy Director Market Oversight & Assessment
Deputy Director Investigations & Enforcement
Hotline
• Public Speaking
• ADR
• Phone answering
Division of Energy Market Oversight
• Electrical Engineers
• Pipeline Engineers
• Economists
• Deep Industry Expertise
• Information Analysts
• Modeling
• Operations Research
• Market Design & Operation
Division of Financial & Integrated Market Assessment
• Engineers
• Economists
• Broad Industry Experience (Cross-Industry, Scenario, Regulatory Analysis; Market Microstructure Issues)
• Understanding of Investment
• Operations Research
• Writing/Presentation Skills
Division of Information Development
• Information Analysts
• Energy Industry Expertise
• Software Applications (Large databases, Data Analysis, Statistics, Presentations (including Mapping)
• Web Experience
• Questionnaire & Survey Design
• Statistical Analysis
Division of Enforcement
• Attorneys
• Litigation
• Investigation
• Knowledge of financial markets
• Enforcement
• ADR Training
• Paralegal
Division of Operational Investigations
• Forensic Auditors
• Analytic ability
• Statistical sampling
• Documentation
• Industry experiences
Division of Technical Investigations
• Gas Engineer
• Electric Engineer
• Mechanical Engineer
• Quantitative Economist

OVERSIGHT AND ASSESSMENT
ACTIVITIES AND PRODUCTS OVERVIEW

	MAJOR PRODUCTS	RELATED ACTIVITIES
MARKETS		
Commodity Prices	Analysis and recommendations regarding anomalous prices or other problematic market behavior Biweekly Surveillance Report and Early Warnings Annual "State of the Markets" (SOM) Report on Structure, Conduct, and Performance; and Quarterly updates ("Report Cards")	Real time monitoring Daily tracking reporting Economic, financial, and policy analysis Support investigations and enforcement initiatives Performance metric development and evaluation
Basis Differentials		
Market Power		
Market Performance		
INFRASTRUCTURE		
Transmission	Annual assessment of adequacy and needs (in SOM) RTO Performance Report Cards	Real time monitoring Tracking, reporting, and analysis of outages Assessments of price effects as function of generation, transmission, and storage status/trends Performance metric development and evaluation
Generation		
Gas Storage		
New Projects	Annual assessment of progress in accelerating approvals and completions	
BACKGROUND		
Weather	Look-ahead scenario development to assess range of important "uncontrollable" factors for quarterly reports Reports on actual versus expected patterns and price behavior Reports on major changes and market implications (M&A, credit watches, regional economic surprises, major policy changes from outside FERC)	Daily monitoring Strategic scanning Analysis of effects on prices and access
Economic Activity		
Corporate Behavior		
Other Regulatory Developments		
Other		

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INVESTIGATIONS AND ENFORCEMENT
ACTIVITIES AND PRODUCTS, BY TYPE OF EFFORT

	HOTLINE	AUDIT	INVESTIGATIONS		
			INFORMAL	FORMAL/ ENFORCEMENT	WITH OTHER AGENCIES
MARKETS					
	Market power abuse Affiliate abuse Other, including tariffs and rates Transmission issues (Gas, Electric, or Oil) Service changes Coordination with OMTR	Market trading practices Market-related transactions ISO/RTO operations RTO Board/MMU independence Affiliate abuse Conformity of RTO rules with tariff and actual operation	Market power abuse Withholding, physical and economic Market rule violation Other Affiliate abuse, for example: Between transmission companies and affiliates Among marketing and supply affiliates Between gas and electric affiliates Market evaluation Commission-sponsored rules Effectiveness of tariffs RTO/ISO tariffs and operations Other (e.g., degradation of service)		
INFRASTRUCTURE					
	Landowners Interconnections Environmental issues	OASIS, Internet postings Transmission or Plant outages NERC/WECC activity Transparency of RTO grid operations Constraints, TLRs and OFOs	Market-related infrastructure issues Outages TLRs, OFOs OASIS, Internet postings Gas Construction Uncertificated construction Certificate violations Construction Environmental Landowner Hydro license issues Unlicensed operation or construction License violations Landowner Environmental Construction Other		
FINANCIAL					
		Track SEC reports Credit ratings AICPA pronouncements Corporate accounting policy			
PRODUCTS					
	Informal dispute resolution Referrals Reports Hotline Overview Hotline Detail Hotline Annual Outreach and marketing	Audit reports Survey reports Fact-finding reports Recommendations	Enforcement Recommendations to Commission Report of investigation Request to initiate formal investigation Consent agreement Show cause order Recommendation for rule or policy change Briefs, motions and other pleadings Quarterly Report of Cases Annual Enforcement Report Sharing information with Other Agencies		

Draft

MANAGEMENT AND COMMUNICATION
ACTIVITIES AND PRODUCTS

STRATEGY & PLANNING	OUTREACH	ADMINISTRATIVE	PUBLICATION
Strategy Message Long-term Strategy Performance Measures (Commission Markets Program) **Planning** Business Planning Office Budget Resource Coordination Office Operation & Program Assessment **Commission Coordination** Agenda Tie-in Inter-office coordination Surveillance reporting process	**Facilitate** **Partnership's with:** MMU/RTO Industry States Academics Think tanks SEC, CFTC, FTC, DOJ Consumer Groups Environmental Entities NAESB Financial Institutions **Awards** Individual and/or to organizations for innovation	**People** Recruitment Career Development Performance Evaluations Fellows Programs and Internships Mentoring Orientation Union Ministerial HR • travel • training • awards • other **Support** Contracts Procurement CIO Logistics Property Internal Controls	**Services** Document repository Powerpoint Education MORe Editing Formating Standards Internet Expertise
PRODUCTS			
GPRA Documents Commission Budget Business Plan Workload Tracking System Agenda Report Coordination	Communication Plan Conferences Speeches Workshops Interviews	New Employees IDP Program Training Sessions Work Environment Resource Acquisition	Reports Articles Glossary Web Page Videos Presentations

Draft

Appendix IV: GAO Contacts and Staff Acknowledgments

GAO Contact

Jim Wells (202) 512-3841
Anu Mittal (202) 512-9846

Acknowledgments

In addition to the individuals named above, R. Stockton Butler, Elizabeth Erdmann, William Lanouette, and Raymond Smith made key contributions to this report. Important contributions were also made by Stuart Kaufman and Barbara Timmerman.

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ORIGINAL

Federal Energy Regulatory Commission
Washington D.C.

Committee on Governmental Affairs
EXHIBIT #A-87

FILED
02 APR 26 PM 4:46
FEDERAL ENERGY REGULATORY COMMISSION

SUBJECT: Tip on Enron Corp's crude oil price fixing

It is recognized that West Texas Intermediate (WTI) is the world base price for Light Sweet crude oil (40° gravity Sweet), and that West Texas Sour (WTS) and is the base price for Light Sour crude oil (34° gravity sour).

EOTT Energy Partners L.P. (EOTT) is a major independent marketer, purchaser and transporter of crude oil in the USA and is a company controlled* by Enron Corp.

EOTT's Posted Prices are manipulated to insure that the purchased crude are below the fair market price. In some instances EOTT may pay a premium above its posted price in order to buy competitive barrels of crude but such adjustments seldom approach the fair market price. In many areas there is little or no competition or the few small competitors consistently track EOTT's posted prices because of the advantages realized. The lower prices paid by EOTT have far reaching effects on all their mineral and royalty owners as well as federal and state governments.

The following are a few examples of EOTT's manipulation of crude oil prices:

1. EOTT's Light Sweet and Light Sour Posted Price is considerably less than WTI and WTS for the same kind and quality crude.

   To illustrate - In February 2002 EOTT's West Texas Light Sweet Posted Price was $3.22/Barrel less than WTI, and EOTT's West Texas Sour was $ 6.89/B less than WTS. Historically EOTT's Light Sweet Posted Price has been lower than WTS (Light Sour).

2. In 2001 the differential between WTI and WTS widened and EOTT's West Texas Light Sweet and its West Texas Sour differential from WTI and WTS also widened. However, when the differential between WTI and WTS recovered to its previous relative relationship, EOTT's differential remained in the same wider relative position resulting in an approximate $3.00/B increase in EOTT's profit.

3. In the areas where it has little competition, EOTT's Posted Prices are far lower than its Posted Prices in other areas of the US where there is competition.

   To illustrate - EOTT's price for heavy sour crude in the Southeast is far below its price in California for similar kind and quality crude. This disparity was so apparent that EOTT stopped publishing its California posting in the summer of 2001.

The result of the above is that EOTT consistently enhances its profit position by the unfair price fixings of its posted price. A detail investigation will confirmed that the statements made are correct and will uncover other price manipulations by Enron.

D

* EOTT's operating General Partner is Eott Energy Corp., which owns all assets of EOTT. Eott Energy Corp. is a wholly owned subsidiary of Enron Corp. The officers and directors of EOTT and Eott Energy are the same and Kenneth Lay, past Chairman of Enron Corp, served on both Boards. Enron Corp owns 36-2/3% of EOTT.

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FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

Committee on Governmental Affairs
EXHIBIT #A-88

OFFICE OF THE CHAIRMAN

August 28, 2002

The Honorable Joseph H. Lieberman
Chairman
Committee on Governmental Affairs
United States Senate
Washington, DC 20510

Re: FERC's Compliance (RM02-11-000) with the 1990 Federal Civil Penalties Inflation Act, As Amended

Dear Mr. Chairman:

On July 16, 2002, the Commission received a letter from the General Accounting Office (GAO) concerning the Commission's compliance with the Federal Civil Penalties Inflation Act of 1990 (Inflation Act), as amended. In the letter, the GAO requests that the Commission submit a written statement to the Committee no later than 60 days after the date of the letter.

In compliance with the Inflation Act, on August 6, 2002, the Commission has issued the enclosed Civil Monetary Penalty Inflation Adjustment Rule, Order No. 890, in Docket No. RM02-11-000. The rule provides for a ten percent initial adjustment to the Commission's civil penalties and subsequent review and adjustments thereafter, as required by law.

As is the Commission's practice, a copy of the GAO's letter and this response have been placed in the public file for Docket No. RM02-11-000. If I can be of further assistance in this or any other Commission matter, please do not hesitate to contact me.

Best regards,

Pat Wood, III
Chairman

Enclosure

cc: Victor S. Rezendes, Managing Director, Strategic Issues, GAO

100 FERC ¶ 61,159

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 385

DOCKET No. RM02-11-000; Order No. 890

Civil Monetary Penalty Inflation Adjustment Rule

FINAL RULE

(Issued August 5, 2002)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is issuing a final rule for a Civil Monetary Penalty Inflation Adjustment as mandated by the Debt Collection Improvement Act of 1996 (DCIA) to adjust the Commission's civil monetary penalties for inflation on a periodic basis. Prior to the enactment of this law, the Commission's penalties had never been adjusted for inflation. This rule will allow the Commission's penalties to keep pace with inflation and thereby maintain the deterrent effect Congress intended when it originally specified penalties.

The first mandatory adjustment, as mandated by the DCIA, increases all of the Commission's penalty provisions by ten percent. The Commission is required to review its penalties again at least once every four years thereafter and adjust them as necessary for inflation according to a specified formula.

DATES: This final rule is effective [insert date of publication in Federal Register].

FOR FURTHER INFORMATION CONTACT:

Carolyn Van Der Jagt
Office of the General Counsel
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426
(202) 208-2246

SUPPLEMENTARY INFORMATION:

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

Civil Monetary Penalty Inflation Adjustment Rule — Docket No. RM02-11-000

ORDER NO. 890

FINAL RULE

(Issued August 5, 2002)

I. **BACKGROUND**

1. The Federal Civil Penalties Inflation Adjustment Act of 1990[1] (Adjustment Act) as amended by the Debt Collection Improvement Act of 1996[2] (DCIA) provided for the regular evaluation of civil monetary penalties (CMP) to ensure that they continued to maintain their deterrent value and that penalty amounts due to the Federal Government were properly accounted for and collected. On April 26, 1996, the Adjustment Act was amended by the DCIA to require that each agency issue regulations to adjust its CMPs for inflation at least every four years. The amendment further provides that any resulting increases in a CMP due to the inflation adjustment should apply only to the violations that occur subsequent to the date of the publication in the Federal Register of the increased

[1] 28 U.S.C. 2461.

[2] 31 U.S.C. 3701.

amount of the CMP. The first inflation adjustment of any penalty shall not exceed ten percent of such penalty.

II. DISCUSSION

2. A CMP is defined as any penalty, fine, or other sanction that: (1) is for a specific monetary amount as provided by Federal law, or has a maximum amount provided for by Federal law; (2) is assessed or enforced by an agency pursuant to Federal law; and (3) is assessed or enforced pursuant to an administrative proceeding or a civil action in the Federal courts. This final rule adjusts the civil penalties that are established by law and assessed or enforced by the Commission.

3. Section 5 of the DCIA sets forth the formula for adjusting the penalties for inflation:

> The inflation adjustment described under Section 4 [of the DCIA] shall be determined by increasing the maximum CMP or the range of minimum and maximum CMPs as applicable, for each CMP by the cost-of-living adjustment. The term "cost of living" adjustment is the percentage for each CMP by which the Consumer Price Index (CPI) for the month of June of the calendar year preceding the adjustment, exceeds the CPI for the month of June of the calendar year in which the amount of such CMP was last set or adjusted pursuant to law.

However, the DCIA also sets a ten percent cap on the first adjustment for inflation. Since the Commission's penalties have never previously been adjusted for inflation, this first statutorily required adjustment will be limited to ten percent.

4. The DCIA rounding rules require that an increase be rounded as follows:

1. If the increase is greater than $0 and less than or equal to $100, round to the nearest multiple of $10.

2. If the increase is greater than $100 and less than or equal to $1,000, round to the nearest multiple of $100.

3. If the increase is greater than $1,000 and less than or equal to $10,000, round to the nearest multiple of $1,000.

4. If the increase is greater than $10,000 and less than or equal to $100,000, round to the nearest multiple of $5,000.

5. If the increase is greater than $100,000 and less than or equal to $200,000, round to the nearest multiple of $10,000.

6. If the increase is greater than $200,000, round to the nearest multiple of $25,000.

5. The Commission is implementing the following adjustments:

United States Code Citation	Civil Monetary Penalty Description	Current maximum penalty amount	New Adjusted maximum penalty amount
15 U.S.C. 3414(b)(6)(A)(i), Sec. 504 Natural Gas Policy Act	Failure to comply with NGPA's provisions	$5,000.00	$5,500.00
16 U.S.C. 823b(c), Sec. 31 Federal Power Act	Failure to comply with rule, license, and permit requirements under Subchapter 12	$10,000.00 per day	$11,000.00 per day
16 U.S.C. 825n(a), Sec. 315 Federal Power Act	Failure to comply with Commission orders and rules, failure to submit required reports	$ 1,000.00	$ 1,100.00
16 U.S.C. 825(o)-1(b), Sec. 316a Federal Power Act	Violation of Sec. 211, 212, 213, 214 of FPA	$10,000.00	$11,000.00

III. ADMINISTRATIVE FINDINGS

6. The Administrative Procedure Act (APA) requires rulemakings to be published in the Federal Register and also mandates that an opportunity for comments be provided when an agency promulgates regulations. However, the APA exempts certain rules of agency procedures from its notice and comment requirements.[3] The Commission is required by the DCIA to adjust CMPs for inflation. Additionally, the formula for the

[3] 5 U.S.C. 553(b).

amount of the penalty adjustment is prescribed by Congress and is not subject to the exercise of discretion by the Commission. The Commission is only required to determine the amount of inflation adjustments by performing administrative computations. Accordingly, the Commission has determined for good cause that public notice and comment are unnecessary, impractical, or contrary to the public interest and that the rule should be published in final form.

IV. REGULATORY FLEXIBILITY STATEMENT

7. The Regulatory Flexibility Act (RFA), as amended by the Small Business Regulatory Enforcement Fairness Act of 1996,[4] (SBREFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Because notice and opportunity for comment are not required by 5 U.S.C. 553, or any other law, a Regulatory Flexibility Analysis is not required and was not prepared for purposes of the RFA.

8. This action will not have a significant impact on a substantial number of small entities. As stated, the Commission is required by the DCIA to adjust civil monetary penalties for inflation. The formula for the amount of the penalty adjustment is

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[4] 5 U.S.C. 801 et seq.

prescribed by Congress and is not subject to the exercise of discretion by the Commission. The Commission's action implements this statutory mandate and does not substantively alter the existing regulatory framework. This rule does not affect mechanisms already in place, including statutory provisions and the Commission's policies, that address the special circumstances of small entities when assessing penalties in enforcement actions.

V. EFFECTIVE DATE

9. For the same reasons the Commission has determined that public notice and comment is unnecessary, impractical, and contrary to the public interest, the Commission finds that it has good cause to adopt an effective date that is less than 30 days after the date of publication in the Federal Register pursuant to the APA,[5] and therefore, the regulation is effective upon publication.

VI. CONGRESSIONAL REVIEW ACT

10. The Congressional Review Act,[6] as added by the SBREFA, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The Commission will submit a report

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[5] 5 U.S.C. 553(b)(3)(B).

[6] 5 U.S.C. 801 et seq.

containing the rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the Federal Register. A major rule cannot take effect until 60 days after it is published in the Federal Register. The Commission has concluded, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs at the Office of Management and Budget (OMB), that this is not a "major rule" as defined in section 251 of the SBREFA. Therefore, for the reasons outlined above, this action will take effect [insert the date of publication in the Federal Register].

VII. INFORMATION COLLECTION STATEMENT

11. The OMB regulations require that OMB approve certain information collection requirements imposed by agency rules.[7] However, this final rule contains no information reporting requirements, and therefore is not subject to OMB approval.

VIII. ENVIRONMENTAL ASSESSMENT

12. Commission regulations describe the circumstances where preparation of an environmental assessment or an environmental impact statement will be required.[8] The Commission has categorically excluded certain actions from this requirement as not

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[7] 5 CFR Part 1320.

[8] Regulations Implementing National Environmental Policy Act, 52 FR 47897 (Dec. 17, 1987), codified at 18 CFR Part 380.

having a significant effect on the human environment.[9] This final rule promulgates a procedural rule that is considered a categorical exclusion under section 380.4(a)(2)(ii) of the Commission's regulations. Therefore, no environmental assessment or environmental impact statement is necessary.

IX. DOCUMENT AVAILABILITY

13. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (http://www.ferc.gov) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, N.E., Room 2A, Washington, D.C. 20426.

14. From FERC's Home Page on the Internet, this information is available in the Federal Energy Regulatory Records Information System (FERRIS). The full text of this document is available on FERRIS in PDF and WordPerfect format for viewing, printing, and/or downloading. To access this document in FERRIS, type the docket number excluding the last three digits of this document in the docket number field.

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[9] 18 CFR 380.4.

15. User assistance is available for FERRIS and the FERC's website during normal business hours from our Help line at (202) 208-2222 or the Public Reference Room at (202) 208-1371 Press 0, TTY (202) 208-1659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

List of Subjects in 18 CFR Part 385

Administrative practice and procedure, Electric power, Penalties, Pipelines, Reporting and recordkeeping requirements.

By the Commission.

(SEAL)

Linwood A. Watson, Jr.,
Deputy Secretary.

In consideration of the foregoing, the Commission is revising Part 385, Title 18 of the Code of Federal Regulations, as follows:

PART 385 - - RULES OF PRACTICE AND PROCEDURE

1. The Table of Contents is revised to read as follows:

SUBPART P - - CIVIL MONETARY PENALTY INFLATION ADJUSTMENT

1. The authority citation for part 385 is revised to read as follows:

Authority: 5 U.S.C. 551-557; 15 U.S.C. 717-717z, 3301-3432; 16 U.S.C. 791a-825r, 2601-2645; 28 U.S.C. 2461; 31 U.S.C. 3701, 9701; 42 U.S.C. 7101-7352; 49 U.S.C. 60502; 49 App. U.S.C. 1-85 (1988).

2. In part 385, subpart P is added to read as follows:

SUBPART P - - CIVIL MONETARY PENALTY INFLATION ADJUSTMENT

Sec.

385.1601 Scope and purpose (Rule 1601).

385.1602 Civil penalties, as adjusted (Rule 1602).

§ 385.1601 Scope and purpose (Rule 1601).

The purpose of this part is to make inflation adjustments to the civil monetary penalties provided by law within the jurisdiction of the Commission. These penalties

shall be subject to review and adjustment as necessary at least every four years in accordance with the Federal Civil Penalties Inflation Act of 1990, as amended.

§ 385.1602 Civil penalties, as adjusted (Rule 1602).

The civil monetary penalties provided by law within the jurisdiction of the Commission are:

(1) 15 U.S.C. 3414(b)(6)(A)(1), Natural Gas Policy Act: from $5,000 to $5,500.

(2) 16 U.S.C. 823b(c), Federal Power Act: from $10,000 to $11,000.

(3) 16 U.S.C. 825n(a), Federal Power Act: from $1,000 to $1,100.

(4) 16 U.S.C. 825(o)- 1(b), Federal Power Act: from $10,000 to $11,000.

JUL 19 2002

Order Transmittal Sheet

Agenda: 7/31/02
M-1

ORDER TITLE	:	Civil Monetary Penalty Inflation Adjustment Rule	
DOCKET NO.	:	RM02-11-000	
ACTION DATE	:	N/A	
CONTACT	:	Governor Jackson 208-0435	OGC - Energy Projects
		Carolyn Van Der Jagt 208-2246	OGC - Energy Projects

The attached draft order implements regulations that would adjust the Commission's civil monetary penalties for inflation on a periodic basis as mandated by The Federal Civil Penalties Inflation Adjustment Act of 1990 as amended by the Debt Collections Improvement Act of 1996.

RFC

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 385

(DOCKET No. RM02-11-000; Order No.)

Civil Monetary Penalty Inflation Adjustment Rule

FINAL RULE

(Issued)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is issuing a final rule for a Civil Monetary Penalty Inflation Adjustment as mandated by the Debt Collection Improvement Act of 1996 (DCIA) to adjust the Commission's civil monetary penalties for inflation on a periodic basis. Prior to the enactment of this law, the Commission's penalties had never been adjusted for inflation. This rule will allow the Commission's penalties to keep pace with inflation and thereby maintain the deterrent effect Congress intended when it originally specified penalties.

The first mandatory adjustment, as mandated by the DCIA, increases all of the Commission's penalty provisions by ten percent. The Commission is required to review its penalties again at least once every four years thereafter and adjust them as necessary for inflation according to a specified formula.

DATES: This final rule is effective [insert date of publication in Federal Register].

FOR FURTHER INFORMATION CONTACT:

Carolyn Van Der Jagt
Office of the General Counsel
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426
(202) 208-2246

SUPPLEMENTARY INFORMATION:

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners:

Civil Monetary Penalty Inflation Adjustment Rule — Docket No. RM02-11-000

Order No.

FINAL RULE

(Issued)

I. BACKGROUND

1. The Federal Civil Penalties Inflation Adjustment Act of 1990[1] (Adjustment Act) as amended by the Debt Collection Improvement Act of 1996[2] (DCIA) provided for the regular evaluation of civil monetary penalties (CMP) to ensure that they continued to maintain their deterrent value and that penalty amounts due to the Federal Government were properly accounted for and collected. On April 26, 1996, the Adjustment Act was amended by the DCIA to require that each agency issue regulations to adjust its CMPs for inflation at least every four years. The amendment further provides that any resulting increases in a CMP due to the inflation adjustment should apply only to the violations that

[1] 28 U.S.C. 2461.

[2] 31 U.S.C. 3701.

occur subsequent to the date of the publication in the Federal Register of the increased amount of the CMP. The first inflation adjustment of any penalty shall not exceed ten percent of such penalty.

II. DISCUSSION

2. A CMP is defined as any penalty, fine, or other sanction that: (1) is for a specific monetary amount as provided by Federal law, or has a maximum amount provided for by Federal law; (2) is assessed or enforced by an agency pursuant to Federal law; and (3) is assessed or enforced pursuant to an administrative proceeding or a civil action in the Federal courts. This final rule adjusts the civil penalties that are established by law and assessed or enforced by the Commission.

3. Section 5 of the DCIA sets forth the formula for adjusting the penalties for inflation:

> The inflation adjustment described under Section 4 [of the DCIA] shall be determined by increasing the maximum CMP or the range of minimum and maximum CMPs as applicable, for each CMP by the cost-of-living adjustment. The term "cost of living" adjustment is the percentage for each CMP by which the Consumer Price Index (CPI) for the month of June of the calendar year preceding the adjustment, exceeds the CPI for the month of June of the calendar year in which the amount of such CMP was last set or adjusted pursuant to law.

However, the DCIA also sets a ten percent cap on the first adjustment for inflation. Since the Commission's penalties have never previously been adjusted for inflation, this first statutorily required adjustment will be limited to ten percent.

4. The DCIA rounding rules require that an increase be rounded as follows:

1. If the increase is greater than $0 and less than or equal to $100, round to the nearest multiple of $10.

2. If the increase is greater than $100 and less than or equal to $1,000, round to the nearest multiple of $100.

3. If the increase is greater than $1,000 and less than or equal to $10,000, round to the nearest multiple of $1,000.

4. If the increase is greater than $10,000 and less than or equal to $100,000, round to the nearest multiple of $5,000.

5. If the increase is greater than $100,000 and less than or equal to $200,000, round to the nearest multiple of $10,000.

6. If the increase is greater than $200,000, round to the nearest multiple of $25,000.

5. The Commission is implementing the following adjustments:

United States Code Citation	Civil Monetary Penalty Description	Current maximum penalty amount	New Adjusted maximum penalty amount
15 U.S.C. 3414(b)(6)(A)(i), Sec. 504 Natural Gas Policy Act	Failure to comply with NGPA's provisions	$5,000.00	$5,500.00
16 U.S.C. 823b(c), Sec. 31 Federal Power Act	Failure to comply with rule, license, and permit requirements under Subchapter 12	$10,000.00 per day	$11,000.00 per day
16 U.S.C. 825n(a), Sec. 315 Federal Power Act	Failure to comply with Commission orders and rules, failure to submit required reports	$ 1,000.00	$ 1,100.00
16 U.S.C. 825(o)-1(b), Sec. 316a Federal Power Act	Violation of Sec. 211, 212, 213, 214 of FPA	$10,000.00	$11,000.00

III. ADMINISTRATIVE FINDINGS

6. The Administrative Procedure Act (APA) requires rulemakings to be published in the Federal Register and also mandates that an opportunity for comments be provided when an agency promulgates regulations. However, the APA exempts certain rules of agency procedures from its notice and comment requirements.[3] The Commission is required by the DCIA to adjust CMPs for inflation. Additionally, the formula for the

[3] 5 U.S.C. 553(b).

amount of the penalty adjustment is prescribed by Congress and is not subject to the exercise of discretion by the Commission. The Commission is only required to determine the amount of inflation adjustments by performing administrative computations. Accordingly, the Commission has determined for good cause that public notice and comment are unnecessary, impractical, or contrary to the public interest and that the rule should be published in final form.

IV. REGULATORY FLEXIBILITY STATEMENT

7. The Regulatory Flexibility Act (RFA), as amended by the Small Business Regulatory Enforcement Fairness Act of 1996,[4] (SBREFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Because notice and opportunity for comment are not required by 5 U.S.C. 553, or any other law, a Regulatory Flexibility Analysis is not required and was not prepared for purposes of the RFA.

8. This action will not have a significant impact on a substantial number of small entities. As stated, the Commission is required by the DCIA to adjust civil monetary penalties for inflation. The formula for the amount of the penalty adjustment is

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[4] 5 U.S.C. 801 et seq.

prescribed by Congress and is not subject to the exercise of discretion by the Commission. The Commission's action implements this statutory mandate and does not substantively alter the existing regulatory framework. This rule does not affect mechanisms already in place, including statutory provisions and the Commission's policies, that address the special circumstances of small entities when assessing penalties in enforcement actions.

V. EFFECTIVE DATE

9. For the same reasons the Commission has determined that public notice and comment is unnecessary, impractical, and contrary to the public interest, the Commission finds that it has good cause to adopt an effective date that is less than 30 days after the date of publication in the Federal Register pursuant to the APA,[5] and therefore, the regulation is effective upon publication.

VI. CONGRESSIONAL REVIEW ACT

10. The Congressional Review Act,[6] as added by the SBREFA, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The Commission will submit a report

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[5] 5 U.S.C. 553(b)(3)(B).

[6] 5 U.S.C. 801 et seq.

containing the rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the Federal Register. A major rule cannot take effect until 60 days after it is published in the Federal Register. The Commission has concluded, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs at the Office of Management and Budget (OMB), that this is not a "major rule" as defined in section 251 of the SBREFA. Therefore, for the reasons outlined above, this action will take effect [insert the date of publication in the Federal Register].

VII. INFORMATION COLLECTION STATEMENT

11. The OMB regulations require that OMB approve certain information collection requirements imposed by agency rules.[7] However, this final rule contains no information reporting requirements, and therefore is not subject to OMB approval.

VIII. ENVIRONMENTAL ASSESSMENT

12. Commission regulations describe the circumstances where preparation of an environmental assessment or an environmental impact statement will be required.[8] The Commission has categorically excluded certain actions from this requirement as not

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[7] 5 CFR Part 1320.

[8] Regulations Implementing National Environmental Policy Act, 52 FR 47897 (Dec. 17, 1987), codified at 18 CFR Part 380.

having a significant effect on the human environment.[9] This final rule promulgates a procedural rule that is considered a categorical exclusion under section 380.4(a)(2)(ii) of the Commission's regulations. Therefore, no environmental assessment or environmental impact statement is necessary.

IX. DOCUMENT AVAILABILITY

13. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (http://www.ferc.gov) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, N.E., Room 2A, Washington, D.C. 20426.

14. From FERC's Home Page on the Internet, this information is available in the Federal Energy Regulatory Records Information System (FERRIS). The full text of this document is available on FERRIS in PDF and WordPerfect format for viewing, printing, and/or downloading. To access this document in FERRIS, type the docket number excluding the last three digits of this document in the docket number field.

15. User assistance is available for FERRIS and the FERC's website during normal

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[9] 18 CFR 380.4.

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(4) 16 U.S.C. 825(o)- 1(b), Federal Power Act: from $10,000 to $11,000.

Committee on Governmental Affairs
EXHIBIT #A-89

FY 2003 CONGRESSIONAL BUDGET REQUEST AND ANNUAL PERFORMANCE PLAN

FEDERAL ENERGY REGULATORY COMMISSION
FEBRUARY 2002

Pat Wood, III
Chairman

Federal Energy Regulatory Commission

Vision

Dependable, affordable, competitive energy markets support a strong, stable national economy

Mission

The Federal Energy Regulatory Commission regulates and oversees energy industries in the economic and environmental interest of the American public.

Values

Employees – People are our most valued asset. We provide the support needed for all employees to excel.

Integrity – We maintain the highest level of professionalism and an environment of fairness, trust, respect, and honesty.

Diversity – We value diversity in people and ideas.

Working Together – We clearly communicate expectations, encourage cooperation and teamwork, and share responsibility.

Progress and Innovation – We are creative and flexible, and seek out opportunities to improve.

Action – Prompt and fair resolution of matters before the Commission is essential to our mission.

Reaching Out – Two-way communication with the public is key to our effectiveness.

Public Service – Our ultimate objective is to provide valued services to the public.

INTRODUCTION

Budget Request: $199.9 Million, 1,250 FTEs

The Federal Energy Regulatory Commission (Commission), requests funding of $199,928,000 and 1,250 FTEs for FY 2003. The funding request includes the agency's full share of accruing employee pensions and annuitant health benefits beginning in FY 2003, per the Administration's proposed legislation. In the table below, the impact of the proposal is applied to all three years for comparative purposes. The request also includes $7 million and 50 FTEs to enhance the Commission's market oversight and investigation capabilities, and funding to cover the projected cost-of-living increase for employees.

Resources by Program
(Dollars in Thousands)

Program	FY 2001 Actual	FY 2002 Estimate	FY 2003 Request	% (+/-) FY 2002 to FY 2003
Energy Infrastructure				
Funding	$55,150	$58,843	$61,690	4.8%
FTEs	468	480	500	4.2%
Competitive Markets				
Funding	$18,195	$20,011	$21,134	5.6%
FTEs	175	180	188	4.4%
Market Oversight				
Funding	$24,323	$26,679	$28,106	5.3%
FTEs	234	240	250	4.2%
Resource Management				
Funding	$80,856[1]	$86,524	$88,998	2.9%
FTEs	292	300	312	4.0%
Total Budget Authority for Operating Expenses				
Funding	$178,524	$192,057	$199,928	4.1%
FTEs	1,169	1,200	1,250	4.2%
Application of Prior Years' Authority	$4,486	$0	$0	N/A
Budget Authority	$183,010	$192,057	$199,928	4.1%
Offsetting Receipts	($183,010)	($192,057)	($199,928)	N/A
Net Budget Authority	**$0**	**$0**	**$0**	**N/A**

This budget request presents funding and FTEs in terms of the Commission's four new challenges or goals, as explained below. The requested resources are broken out by industry in Appendix C. This request does not reflect any requirements that would result from potential changes to the Commission's statutory authority.

Full Cost Recovery

We recover the full cost of our operations through annual charges and filing fees assessed on the industries we regulate. We deposit this revenue into the Treasury as a direct offset to our appropriation, resulting in a net appropriation of $0.

[1]Funding for Resource Management includes information technology costs and rent.

A New Way of Operating

Background

In the aftermath of the electricity crisis in the Western United States, we comprehensively revised our Strategic Plan. We are now developing a comprehensive Business Plan that aligns all of the activities we undertake with the new Strategic Plan. This budget request reflects the change in strategic direction outlined in the new Strategic Plan.

California was among the first states to open its electric industry to competition, opening a restructured market in 1998. Until June 2000, California's electric markets appeared to work well. However, California's flawed market rules failed to send generators signals to build new capacity, even while the state experienced rapid economic growth. The lack of new capacity made the California market vulnerable. In 2000, a series of other conditions exposed that vulnerability: a severe drought curtailed hydropower; demand-side response was virtually non-existent, partly because of fixed retail rates; and a hot summer followed a cold winter. The balance between supply and demand tightened, and electric prices rose dramatically.

We acted to mitigate the sharp price increases of electricity and natural gas in the Western states. These measures provided customers with relief from the most extreme spot market prices. We also removed a series of regulatory obstacles to expedite providing increased energy supplies to the West. Since June 2001, electric prices have dropped to normal levels and below, throughout the West, and remained there. Several factors led to this result: reduced demand, relatively mild weather, increased supplies, and our price mitigation. Nonetheless, it is abundantly clear that market crises can erupt quickly, especially in electricity. If not prevented or treated quickly, they can do enormous damage.

Given the experience of Western energy markets, it is now clear that our primary emphasis must be to facilitate a full transition to competitive wholesale energy markets as soon as possible, and to address crucial issues that arise during the transition. Our most important responses are:

- **A New Sense of Focus and Direction.** This is embodied by our new Strategic Plan, which forms the structure for both this budget and our efforts in the future.

- **An Increased Emphasis on Market Oversight and Investigation.** This is embodied in the third of our four challenges, discussed below.

A New Strategic Plan

The new Strategic Plan lays out challenges, or goals, in four areas:

1. **Energy Infrastructure.** Goal: Promote a Secure, High-quality, Environmentally-responsible Energy Infrastructure Through Consistent Policies. This goal will encourage investment in the infrastructure needed to sustain energy markets by removing roadblocks, providing cost recovery clarity, and welcoming innovative thinking about rates and use of new technology. By focusing on infrastructure, this goal covers many of the Commission's important traditional responsibilities, for example, pipeline certificates, hydropower licenses and preliminary permits, compliance activities, environmental and other licensing conditions, dam safety inspections, and most rate determinations.

2. **Competitive Markets.** Goal: Foster Nationwide Competitive Energy Markets as a Substitute for Traditional Regulation. This goal focuses on our need to complete the transition to competitive energy markets as quickly and comprehensively as possible. This will require the growth of many new institutions, particularly clearly defined and independent regional transmission organizations (RTOs), to make electric markets work. We also need to establish standardized market designs that will apply in every wholesale electric market, and encourage continued efforts by industry groups to standardize reliability and business practice standards, promote the use of demand-side participation in energy markets, and establish regional transmission planning. Along with some traditional work in the area of rate determinations, this goal furthers work on initiatives begun in the last couple of years such as RTOs and new policies for natural gas.

3. **Market Oversight.** Goal: Protect Customers and Industry Participants Through Vigilant and Fair Oversight of the Transitioning Energy Markets. This goal will ensure that competitive energy markets benefit the Nation over the long run. We are establishing a new office to coordinate all market oversight and investigative activity. We need a much stronger ability to recognize and respond to problems in the markets. At the systemic level, we need to recognize problems when – or before – they develop and craft solutions quickly. We must also be able to police individual behavior in markets much more effectively than in the past. Work toward this goal also includes more traditional work, such as some aspects of litigation, dispute resolution, complaints, mergers, and auditing.

4. **Resource Management.** Goal: Efficiently Administer the Agency's Resources to Accomplish the Agency's Goals. We will be unable to meet our programmatic challenges without management support. This includes enhancing the talents and skills of the staff through recruitment and training, building effective, customer-friendly information technology (IT) services, supporting the Commission with logistics and

financial services, and strengthening our strategic management processes. This goal also covers our communication, outreach, and collaboration efforts. The requested funding for this goal includes major expenses such as rent and IT equipment.

Additional Resources Requested for Market Monitoring and Investigation

A successful transition to competitive energy markets will require an enhanced effort to prevent severe market malfunctions and the exercise of market power, and to respond quickly to problems that arise. It is now clear that these efforts are especially important during the transition period when markets are coming into existence. This budget request includes an additional $7 million and 50 FTEs to develop and enhance our market oversight and investigation capabilities. Chapter 3 details how we will use these extra resources and discusses appropriate performance measurements for the function.

Overview of the Document

The next four chapters detail plans to meet each of the goals in the Strategic Plan. Each chapter contains a discussion of goals and objectives and projected performance measurements. Our performance plan for FY 2003 is presented as an integral part of these chapters. A series of appendices provide further details.

CHAPTER 3: MARKET OVERSIGHT

Protect Customers and Market Participants Through Vigilant and Fair Oversight of the Transitioning Energy Markets

Operating Expenses

(Budget Authority Dollars in Thousands)

	FY 2001 Actual	FY 2002 Estimate	FY 2003 Request
FTEs	234	240	250
Funding	$24,323	$26,679	$28,106

Introduction

Recent experience makes it very clear that good energy markets require good market regulators. We recognized the importance of developing strong market oversight and investigatory capabilities several years ago and began a systematic program to develop them in 1999. The California crisis showed that the need for good oversight and investigation is not only important but also far more urgent than we (or most others) had fully understood. We also need to build a better understanding of the dynamics among players, market events, prices, and volumes within a market, and to identify the data and metrics that reveal market activities, outcomes, and effectiveness. As a result, we are establishing a new Office of Market Oversight and Investigation (OMOI), a high-level organization directly under the Chairman. We are asking for an increase of $7 million and 50 FTEs to build our oversight and investigatory capabilities. This will let us supplement our limited expertise in the following areas:

- *Investigation.* We have little experience with intensive market investigations of the sort that is routine at agencies such as the Commodity and Futures Trading Commission.
- *Market Operations.* We need more people who are familiar with the details of how electric and natural gas markets actually work.
- *Risk Management and Derivatives.* We need a much greater understanding of how financial and physical markets interact, both in daily trading and in making long-term investment decisions.

- *Investment in Unregulated Industries.* We have many people who understand how investment decisions happen in traditional regulated industries. However, we need people who can assess how our actions affect those who invest in market-oriented industries, including electric generation.

- *Market Information Analysis.* We have many people who can analyze traditional rate filings and even individual filings for market-related activities. Market performance can be measured using the explosion of data that markets produce. We need data analysts who can use data management and analytical tools that go far beyond the capability of spreadsheets.

- *Engineering to Integrate Analysis of Market and Physical Systems.* Electric and natural gas markets differ from most commodity markets because the physical transmission system frequently imposes constraints that can radically shift economic results. We need people who can relate market activities to the underlying physical constraints of the transportation systems.

We have three main objectives in meeting this Challenge:

- Improve our Understanding of Energy Market Operations,
- Assure Pro-competitive Market Structures, and
- Remedy Individual Market Participant Behavior as needed to Ensure Just and Reasonable Market Outcomes.

The first objective is essentially educational, to ensure that as an institution we understand enough to regulate the market successfully. The second objective concerns market oversight. It looks at overall market structure and performance and attempts to prevent possible future problems. The third objective covers enforcement. It examines individual companies and seeks to remedy past problems.

Objective 3.1: Improve Our Understanding of Energy Market Operations

The first step in meeting this challenge is to understand the markets that we oversee. Institutionally, that means we must:

- Learn how energy markets are evolving. Given the extraordinarily dynamic nature of electric and natural gas markets, this will require a sustained effort over a fairly long period of time.

- Ensure that all of our staff who are involved in market oversight and investigation understand emerging market developments and can relate them to their immediate work.

- Ensure that most of our staff has a basic understanding of market functioning so that the decisions they make in case analysis and rulemakings support the growth of competitive energy markets.

To achieve these ends, we will use the following strategies:

Keep Abreast of Market and Technological Innovation, Including Use of Financial Instruments and Internet-based Energy Trading.

As energy markets develop, we must continually update our understanding of how they are working and how market changes affect all aspects of our work. We will focus on new market developments (for example, new derivatives and Internet trading), new technologies (for example, distributed generation, superconducting transmission), new business strategies, new approaches to regulation and new interactions with other industries and markets (for example, emissions trading).

Develop Staff's Investigatory and Market Data Analysis Skills Through Training, New Hiring and Relationships with Outside Experts.

Market investigations involve types of information and behavior that are unfamiliar to most traditional cost-of-service regulators. They require forms of investigation that differ from our traditional work. We will use expertise from those who already investigate other markets. This will include hiring some experts directly, contracting with others, and partnering with other agencies that have more expertise. From this, from market observation, and from strategic skills training, we will build staff experience.

Strengthen Role of RTO Market Monitoring Units.

Given how quickly electricity markets can change, market monitoring is clearly an essential part of any future market. RTOs will be much closer to regional markets than either state or federal regulators. So it is natural that the first responsibility for market monitoring should rest with RTOs. We will work with the industry to define clearly what an RTO's market monitoring must encompass. We will build on the experience of some of today's ISOs, who have well developed market monitoring programs. We will work with RTOs to ensure that they have effective market monitors in place, that the market monitoring efforts of RTOs in different parts of the country are consistent, and that there are appropriate regulatory backstops when market monitors identify problems.

Improve Data Collection.

We will collect the data we need to understand energy markets. This means collecting data that are more strategically valuable – that is, data that meaningfully describe market performance and that let us pinpoint possible problems for further investigation. We will fully use data from publicly available sources, as well as collecting more timely and frequent data from more market players, with Congressional authority, if necessary. At the same time, we will reduce or eliminate data collections that are no longer necessary for market-oriented industries.

Objective 3.2: Assure Pro-competitive Market Structures

Competition is making the electric and natural gas industries very dynamic. We must make sure that the market structures and rules we help put in place

today both work well today and provide a framework that will serve evolving markets in the future. To do so, we need to track market behavior and evaluate market performance so that we can understand and discern:

- the difference between superficial and significant market problems;
- which market problems are due to market rule or structural flaws and which are due to misbehavior; and
- which market problems require regulatory intervention and which require only patience.

Identify and Remedy Problems Concerning Market Structure.
Assess Market and Infrastructure Conditions Through Use of Objective Benchmarks.
Periodically Review Effectiveness of Market Rules and Revise Them Consistent with Sustained, Long-term Development of Energy Markets.

At the heart of this effort will be a twice-yearly Seasonal Market Assessment, to be published in advance of the summer cooling season and the winter heating season. The Seasonal Market Assessment will examine all major regional markets for both natural gas and electric power. It will report on a series of objective measurements for each market, including basic supply-demand balances, transportation adequacy, and the degree of market concentration. It will also report experience with current market rules (both positive and negative) and assess whether there are any major vulnerabilities that might threaten market disruptions in the future. Finally, it will prioritize recommended actions needed to improve market performance or prevent disruptions. Overall, this report will provide the market performance assessment to correct major potential problems in the markets before they become serious.

We will supplement the Seasonal Market Assessment with other periodic reports, including bulletins that analyze fast-breaking market developments. Information will come from our Market Observation Resources Room, the automated center that gives us the ability to follow market activities as they happen, and from significantly improved industry contacts, including close coordination with RTO market monitors. These reports also will include analyses of apparent market anomalies – for example, times when prices seem to be high in unexpected places or volumes seem abnormal. Such anomalies can indicate problems with data, new patterns of market trading, or various forms of gaming.

Ensure That Mergers and Consolidations Are Consistent with Pro-competitive Goals.

Most industries that move toward lighter forms of regulation witness considerable restructuring, including consolidations of companies within individual segments of the industry. Mergers can bring efficiencies from economies of scale and can also represent the result of successful competition when more effective business models grow. However, mergers also eliminate competitors and can lead to markets that are too concentrated to be fully competitive. We will examine mergers over

which we have jurisdiction in light of emerging market realities, to ensure that future mergers do no harm to the Nation's overall goal of a competitive set of energy markets.

Objective 3.3: Remedy Individual Market Participant Behavior as Needed to Ensure Just and Reasonable Market Outcomes

The purpose of making energy markets work is to bring the benefits of competition to customers all over the country. Our direct responsibility is to protect wholesale customers. But wholesale and retail markets are so closely integrated that our efforts to protect wholesale customers are a necessary foundation for state efforts to protect retail customers. Energy markets will produce just and reasonable results for customers, as markets have done in many other industries, but only if:

- *The markets really are competitive.* Customers must not be subject to abuses of market power that bring benefits to the supplier but not the customers.
- *The customers have recourse when there is a problem.* Customers who feel abused must have a trusted body that will investigate their claims and redress any valid complaints.

As a result, we need to develop a first-rate market investigations program that gives all individuals in the markets reason to believe that the market will operate fairly for all. Establishing the credibility of this program is our most urgent task in protecting customers and market participants. To do this, we will:

Identify and Mitigate Market Power, and Use Prohibitions and Penalties as Necessary.

In highly dynamic industries, market participants constantly seek new profit opportunities, including new ways to use market power. To protect customers, we will detect abuses of market power quickly. To do this, we will pay close attention to complaints as we receive them. We will also develop our own analytic capabilities. For example, we may devise automated audits that flag potential abuses. We will devise remedies that remove the effects of market power (mitigation), that prevent abusive actions (prohibitions), and that deter future abuses (penalties). And we will apply the remedies to match the specific facts in individual cases.

Initiate and Conduct Timely and Effective Investigations as Warranted by Factual Reviews.

Our enforcement activities depend on the timeliness and quality of our investigations. We will upgrade our investigative staff by increasing their numbers and improving their expertise. Where we do not have the expertise in either market operations or how to conduct a market investigation, we will obtain the expertise we need. We will establish clear targets for how long investigations of different types may take and we will hold ourselves accountable to those targets.

Act Swiftly on Third-party Complaints, Using Litigation Before Administrative Law Judges as Necessary to Determine Factual Issues.
In some cases, the best approach to a possible abuse of market power will be through our formal litigation process. This is especially the case when it is important to establish in open procedures exactly what the facts of a case are. Litigation can be costly and time-consuming, though we are seeking to streamline the process as much as possible. However, the openness of the process can promote credibility in important cases.

Develop Expedited Dispute Solving Mechanisms to Minimize Time and Personnel Use.
Many commercial disputes are important for the individuals involved, but do not raise major issues of fact or policy. This will be true for many or most disputes in energy markets as well. We will continue to develop our systems for alternative dispute resolution (ADR) so that such cases can be resolved relatively quickly, inexpensively, and satisfactorily for all parties involved. These ADR techniques include the use of settlement judges and the use of neutrals both from the Commission's Dispute Resolution Service and from outside.

Measuring Success

We use both outcome and output performance measures to measure the effectiveness of our programs. Output measures describe how quickly or how well we produce our specific work products – for example, orders, decisions, environmental reviews. Outcome measures describe how well we are succeeding in our larger goals for American energy industries.

Outcome Measures

This challenge calls on us to make sure that wholesale markets are working for customers. We have not yet developed precise outcome targets for our success. However, our efforts to make sure that markets work will have important, observable effects for customers. Key among these are the following:

- **Severe Market Disruptions Will Either Be Prevented or Corrected Rapidly.** If this happens, the Nation will avoid a sustained systemic instability like that which affected Western energy markets in 2000-2001 and could provide a secure base for the future growth of strong competitive markets.

- **Electric and Natural Gas Transportation Customers and Electric Wholesale Customers Will Have Access to a Range of Competitive Alternatives, Including Innovative Products and Services.** To choose as performance targets any particular market outcomes (given prices or volatilities, for example) would not serve our purpose. However, it is reasonable to say that customers should see the value of competition in the form of more attractive choices. Then they could choose, for example, whether to purchase better service at a higher price or lesser service at a lower price.

The market oversight accomplished in meeting this Challenge will also enhance our outcomes in meeting other challenges. Key outcomes of this sort will include:

- **Congestion Costs on the Electric Grid Will Be Lower.** By identifying key infrastructure projects that are needed in time to facilitate a timely remedy (Energy Infrastructure), it should be possible to reduce the effects of bottlenecks in the grid. This will improve competitive options across larger geographic areas and will be manifest in lower overall congestion costs associated with transmission.

- **There Will Be Fewer Operational Flow Orders (OFOs) on Natural Gas Pipelines.** By identifying needed pipeline projects in time to facilitate their timely completion (Energy Infrastructure), it should be possible to reduce bottlenecks in the natural gas grid. This would reduce the number of OFOs that pipelines declare. OFOs should also decline as a result of improving business standards (Competitive Markets).

- **RTOs Will Operate Nationwide.** Market oversight will enable us to ensure that RTOs operate well in all parts of the country (Competitive Markets).

Devising operational measurements for some of these outcomes will be difficult. However, in each case, results are both potentially observable and important to measuring the success of the agency.

Output Measures

We have three overarching output targets for this challenge:

Measures	Targets	Data Source
Enhance institutional capability for overseeing energy markets	• Establish the Office of Market Oversight and Investigation • Publish regular summer and winter Seasonal Market Assessments • Develop metrics/indicators of gas and electric market performance measures – a working set by July 2002, and improvements in 2003	Office of Market Oversight and Investigation

We also have a series of more specific performance targets:

Measures	Targets	Data Source
Top to bottom review of all existing information systems to monitor markets	Complete entire review	Office of Market Oversight and Investigation
Development or acquisition of usable electronic baselines and databases to support market oversight objectives	Complete development of all baselines and databases by end of FY 2003	Office of Market Oversight and Investigation

(Continued on Next Page)

Measures	Targets	Data Source
Development of market expertise	• Training on market issues for 40% of OMOI and 20% of OMTR, OGC, and other staff • Hiring of staff with market expertise • Issuance of market assessment products and data analysis demonstrating market understanding	Office of Market Oversight and Investigation
Establishment of protocols between the Commission and independent market monitoring units of RTOs	All approved RTOs	Office of Market Oversight and Investigation
Timeliness of corporate application orders	Less than 20% of merger applications will require examination or the imposition of mitigation measures beyond the initial review period, with such percentage targeted to decrease as further policy guidance is issued in cases requiring more time to address market power	Office of Markets, Tariffs, and Rates
Timeliness of audits	Complete 90% of audits on time	Office of Executive Director
Timeliness of Hotline calls resolutions	Resolve 80% within 1 week of initial contact	Office of General Counsel/Office of Market Oversight and Investigation
Timeliness of formal complaints resolutions	Complete 80% within target time frames for various paths for resolution of complaints as specified by the Commission	Office of General Counsel/Office of Administrative Law Judges/Office of Market Oversight and Investigation
Number of requests and referrals for ADR services	Maintain at or increase levels achieved in FY 2001	Dispute Resolution Service/Office of Administrative Law Judges
Percentage of customers satisfied with ADR processes	85%	Dispute Resolution Service/Office of Administrative Law Judges
Percentage of processes that achieve consensual agreements	Maintain at or increase levels achieved in FY 2001	Dispute Resolution Service/Office of General Counsel/Office of Administrative Law Judges
Percentage of cases in time frames • ADR processes completed • litigated cases reaching initial decision	• 20% of ADR cases within 60 days • 30% of ADR cases within 100 days • 75% of ADR cases within 150 days • 100% of ADR cases within 200 days • 95% of simple litigated cases within 206 days (29.5 weeks) • 95% of complex litigated cases within 329 days (47 weeks) • 95% of exceptionally complex cases, 441 (63 weeks) • 95% of regular complaints, 60 days • 95% of "fast track" complaints, 8 days	Dispute Resolution Service/Office of General Counsel/Office of Administrative Law Judges

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

Committee on Governmental Affairs
EXHIBIT #A-90

OFFICE OF THE CHAIRMAN

August 19, 2002

The Honorable Joseph H. Lieberman
Chairman
Committee on Governmental Affairs
United States Senate
Washington, D.C. 20510

Re: GAO Report Entitled Energy Markets: Concerted Actions Needed by FERC to Confront Challenges That Impede Effective Oversight

Dear Mr. Chairman:

In June 2002, the General Accounting Office (GAO) issued a report, Energy Markets: Concerted Actions Needed by FERC to Confront Challenges That Impede Effective Oversight. The report found that the Commission faced key challenges in overseeing energy markets:

- Our organizational structure limited the effectiveness of our oversight program because there was not sufficient focus on the problem;
- We had not defined and implemented an effective approach to overseeing competitive energy markets; and
- We faced significant challenges in addressing our human capital needs.

In addition, the report found that new statutory authority and guidance from Congress would enhance our ability to develop, regulate and oversee competitive energy markets.

In commenting on the report, I generally agreed with the conclusions and said that the Commission was moving aggressively to address the challenges. I welcome this chance to report to you on the progress we have made in the 60 days since GAO issued its report, as required by law.

We have given Market Oversight the Organizational Structure it needs. In January 2002, we announced a new Office of Market Oversight and Investigations (OMOI) to oversee the operations of electric and natural gas markets. I promised that OMOI would be up and running in August 2002 and that it would report directly to me and my fellow Commissioners, bring together all of the staff devoted to

oversight and enforcement, and receive the resources it needs to restore and maintain the integrity of our nation's energy markets.

OMOI is in operation. On August 12, 2002, OMOI became a formal, functioning Office within the Commission. This reflects four months of intensive effort on the part of Commission staff (see Attachment A – OMOI Action Timeline). OMOI reports directly to me for administrative purposes. We have also designed a new agenda process so that OMOI reports directly to all of the Commissioners on market oversight and enforcement matters. As a result, market oversight and enforcement now has equal weight with more traditional forms of regulation in the Commission's deliberations.

We have already transferred many of the oversight and investigation responsibilities to OMOI and will very soon transfer the rest. All of the core functions that OMOI will perform are now within the Office, except for the attorneys involved in enforcement actions (see Attachment B - OMOI Organizational Chart). We have hired the Deputy Director for Market Oversight and Assessment. We have also selected the Deputy Director for Investigation and Enforcement that is pending OPM approval. The enforcement attorneys will transfer over soon after the Deputy Director is on board.

OMOI is getting the resources it needs. OMOI currently has 57 employees on board and is recruiting for additional positions. We have budgeted for the Office to have 110 full-time equivalents (FTEs) in FY 2003 and 120 FTEs in FY 2004. We have also budgeted $500,000 and $1 million, respectively, in contract dollars to obtain other expertise that we will need.

We have made substantial progress in defining and implementing an effective approach to market oversight. During the past four months, even before OMOI began formal operation, we developed a blueprint for what the office will do, and we have begun to deliver the products that will define the office in the future.

We have developed our first working blueprint for what market oversight and assessment must do. We have proposed revisions to Goal 3 of Commission's Strategic Plan to reflect more precisely how we intend to oversee markets. Based on the revised Strategic Plan, we have developed a Business Plan that describes the activities OMOI will undertake, the products those activities will generate and the resources we plan to spend on each activity (see Attachment C – Challenge 3 Business Plan). Together the revised Strategic Plan and the Business Plan are the best blueprint the agency has ever had for how it will oversee markets. While the Business Plan will evolve, it is specific enough to guide our work now and provide a platform for changes that will be needed as we develop our capabilities in the future. We have also defined clearly the missions and functions of the major

organizational units within OMOI – Market Oversight and Assessment, Market Investigations and Enforcement, and the Division of Management and Communication (see Attachment D – OMOI Mission and Functions Statement).

We are already implementing our new approach to market oversight. At the heart of our efforts to analyze and assess energy markets is a series of periodic reports to the Commission, which will include:

- A biweekly Surveillance Report. This will report on important issues in energy markets as they develop.

- A semi-annual Seasonal Outlook. The Outlook published in October will look forward to the winter heating season and report on overall market conditions and issues that may arise during the coming season. The Outlook published in April will do the same for the summer cooling season.

OMOI has already begun both these reports. It has now produced four Surveillance Reports that it has delivered directly to the Commission in closed sessions during June and July 2002. Similarly, it produced a first test version of the Seasonal Assessment for the summer of 2002 at the beginning of July (see Attachment E – Summer 2002 Assessment Briefing Slides). Both reports will improve significantly over time. We think it is vitally important that they are already underway – demonstrating our readiness to act on these matters.

Similarly, OMOI has begun an aggressive program of outreach to a wide variety of entities, including:

- Other regulatory agencies;
- Industry participants;
- Academic institutions and think tanks;
- Financial institutions (such as ratings agencies); and
- Market Monitoring Units (MMU) at Regional Transmission Organizations and Independent System Operators.

The purpose of the outreach is both to let these entities know that the Commission is developing a clear market oversight capability and to obtain their ideas for how best to develop that capability.

Next steps will be crucial. We now have a good foundation for an effective market oversight program. The next challenge is to build a first rate capability on that foundation. The most important next steps will be:

- Integrating enforcement and investigation functions into OMOI. That will let us begin implementing our long-term plans for ensuring our rules are followed.

- More periodic reports. In addition to the Surveillance Report and the Seasonal Assessment, we will develop two other forms of periodic reporting. The first is a real-time alert system. This will give Commissioners quick access to breaking news and as much analysis as is possible in a short time. That, in turn, will help the Commission respond much more quickly and cogently when market issues develop suddenly. The second is an annual "state of the markets" report that will be published in January each year. This report will look at the overall situation of American energy markets and will include performance measures both for the markets themselves and for the Commission.

- Better processes. We are developing streamlined processes for all of our major activities. This will free up staff resources for in-depth work both to analyze particular aspects of energy markets and to support investigations.

- Better analysis of financial markets. Our biggest analytic gap is in analyzing the financial markets that underpin energy markets – markets for investment capital and risk management. We will develop the expertise we need in these areas (through hiring) and improve our reporting over the next few months.

- Developing a full partnership with MMUs. MMUs will be the first line of defense in analyzing market problems, especially as they arise over short time periods. We must develop a very close partnership with them. We have already begun planning to co-locate some Commission staff with the California ISO. We will be developing and implementing plans to build partnerships with the other MMUs.

We have accomplished significant efforts to monitor markets. The Commission has acted in numerous ways to monitor and act on market issues. These include:

- Commission staff released an initial report of its fact-finding investigation of potential manipulation of electric and natural gas prices. The interim report is the result of an ongoing time- and resource-intensive investigation by FERC staff, analyzing extensive responses from more than 100 companies, interviewing market participants, conducting on-site inspections and coordinating with the Department of

Justice (DOJ), the Commodity Futures Trading Commission (CFTC) and the Securities and Exchange Commission (SEC).

- The Commission launched formal investigations into instances of possible misconduct by six companies based on a staff probe of electricity and gas market manipulation in Western energy markets. Commission staff will continue to investigate the trading operations in the Western markets before issuing a final report.

- On July 31, 2002, the Commission released a landmark proposed rule, "Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design," that includes a comprehensive market power and market manipulation mitigation plan. The plan includes conduct rules that will be monitored and enforced by Market Monitoring Units of the Independent Transmission Providers and FERC's OMOI.

- The Commission issued energy market disclosure and market transparency rules through Order No. 2001 in April 2002 and a companion rehearing order in June 2002. The first installment of bilateral trading data was due July 31, 2002. These rules allow market monitoring to be performed not only by regulators but by any customer or market participant to provide greater confidence in the integrity of the market.

- The Commission has acted on a number of cases based on market monitoring findings and proposals. For example, on July 17, 2002, the Commission approved a series of market mitigation measures for Western power markets that will replace the previous measures adopted in June 2001. The plan was based in large part upon the findings and proposals of the Market Surveillance Committee of the California Independent System Operator. The order was also based on an extensive report by Commission staff examining the interdependence of the western states' energy needs, market indicators, and the changes in infrastructure. The study focuses on current and projected market conditions for electricity and natural gas supply, demand, and transmission, and the creditworthiness of the companies providing service in western markets.

- The Commission formalized its planned interaction with Market Monitoring Units with a public meeting on June 26, 2002. Market monitors from ISO New England, New York ISO, PJM Interconnection, the California ISO, and the American Electric Power (AEP) system

presented the results of their annual state of the markets reports. These reports identified market design flaws, perverse incentives that lead to inefficient behavior, market manipulation, and market power issues. The market monitors spoke directly with the four Commissioners and staff about processes, issues, and proposed solutions. Overall, each of the market monitors deemed their markets to be functioning in a workably competitive manner but requiring further attention.

- The Commission is pursuing efforts to obtain new data sources. We have recently gained access to NERC tagging data which allows us to know hour by hour who is using the electric transmission grid and power plant generation data that tells us the level at which power plants are generating.

We are addressing our Human Capital Challenges. The Commission has undertaken a number of human capital initiatives. By offering early outs and buyouts, the Commission is seeking to address existing skill mix problems. Resources are being freed up so they can be redirected to program offices in order to augment market oversight capabilities.

Both the Office of Markets, Tariffs, and Rates (OMTR) and OMOI are examining how to meet their needs for additional employees with market-oriented skills. OMTR is working with the Human Resources staff to post positions outside the Commission for high-level subject matter experts as part of an upcoming office reorganization. OMOI is seeking to augment all levels of existing staff capabilities by hiring new employees with private sector experience and is advertising these positions in a variety of print and electronic media (see Attachment F – OMOI Hiring and Recruiting). In addition, OMOI has posted the first of the senior level positions authorized by the Office of Personnel Management to recruit employees with extensive market-oriented expertise who can lead market oversight activities.

The Human Resources staff has begun a Workforce Planning effort involving representatives of major program and support offices. Office representatives are examining workload priorities, existing workforce capabilities and skills, future skills and staffing needs, and strategies for closing identified gaps. This effort is tied to the Commission's strategic plan and will produce a blueprint for action on critical human capital issues.

With respect to legislative authority, we have requested enhanced civil penalty authority for both jurisdictional natural gas and electricity markets and have supported enhanced Federal regulation of energy commodities markets. As to penalties, I have testified that Congress could create additional deterrents to anti-

competitive and bad-faith behavior in the marketplace by broadening and strengthening the Commission's civil penalty authority. We stand ready to implement any additional responsibilities authorized by Congress through the initiatives now under their consideration.

In the last two months, FERC has done much to address the key challenges identified in the GAO's report. We have significantly improved our ability to monitor and assure the competitiveness of America's wholesale energy markets, and we thank the GAO and Congress for its commitment, advice and support.

Best regards,

Pat Wood

Pat Wood, III
Chairman

Attachments

cc: Jim Wells, Director, Natural Resources and Environment, GAO

Attachment A

OMOI Action Timeline
(2001 - 2002)

September

- Adoption of revised agency strategic plan

September to December

- Research and plan to implement Market Oversight and Investigations strategic challenge from the plan

January

- FERC posts OMOI Director position

April

- FERC Chairman appoints OMOI Director (William Hederman)
- FERC All-Hands meeting held to discuss the creation of OMOI
- Ten-member implementation team named

May

- Draft OMOI implementation plan sent to Chairman with proposed organization chart and statement on vision, mission, functions
- Initiate limited external recruiting efforts

June

- Chairman and Union approve plan
- At All-Hands meeting, FERC staff updated on OMOI progress and invited to submit expressions of interest in joining OMOI. Result: 175 Expressions of Interest
- 35 FERC staff selected, assigned to OMOI
- Bi-Weekly "Energy Market Surveillance Report" launched
- Orchestrated Market Monitors presentations of State of the Markets reports at Commission Meeting
- Market Oversight Resources (MOR) Room enhanced for additional real-time market monitoring

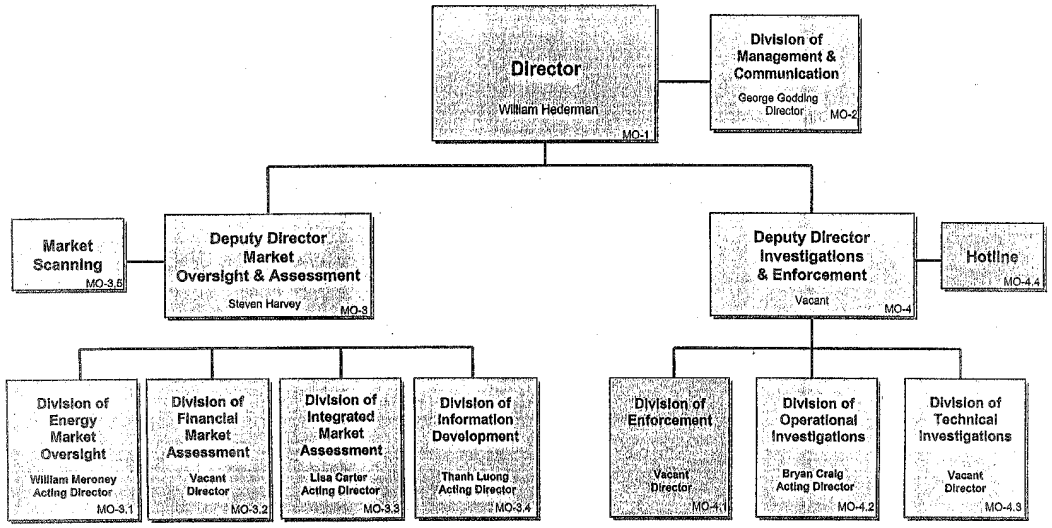
July

- Notices posted for 2 deputy directors, attorneys, senior economists, other experts
- Effort begun to staff California regional office
- Summer Market Assessment Overview completed and presented at Commission Open Meeting
- Ten teams formed to ramp up OMOI, focusing on primary reports, managerial/administrative issues and identifying information needs
- Deputy Director, Oversight & Assessment, selected; joins staff
- Skillset gap analysis done; full scale recruitment of expertise from outside begun

August

- OMOI officially established; 60 staff on board; 60 vacancies
- Deputy Director, Investigations & Enforcement, selected (awaiting OPM approval)
- Initial information needs defined and reports (daily to annual) refined
- Divisions of Oversight & Assessment and Management & Communication defining processes, needs, procedures
- Winter Assessment initiated

Office of Market Oversight and Investigations (OMOI) Organizational Chart



Attachment B

Goal 3: Protect Customers and Market Participants through Vigilant and Fair Oversight of the Transitioning Energy Markets

Objective 3.1: Promote understanding of energy market operations and innovation

Strategy 3.1.1: Develop and maintain an expert market oversight and investigation staff

Activity	Priority	Dates	FTE '03	FTE '04
Recruit and orient new employees (See Objective 4.1)			0	0
Develop and give technical training courses			0.5	0.5
Receive technical training			2	2
TOTAL Strategy 3.1.1			*2.5*	*2.5*

Strategy 3.1.2: Keep abreast of industry and market trends and technological innovations to inform and guide market oversight

Activity	Priority	Dates	FTE '03	FTE '04
Track energy market trends and technological innovations and evaluate potential effects on energy markets		Quarterly	2	2.5
Modify activities and organization to shape market oversight program to the needs of developing markets		Quarterly	1	0.5
TOTAL Strategy 3.1.2			*3*	*3*

Strategy 3.1.3: Enhance the Commission's deliberations and public discussion by developing market information and disseminating findings

Activity	Priority	Dates	FTE '03	FTE '04
Determine information needs				
For ongoing market oversight			1.5	0.5
For individual efforts			0.5	0.5
Acquire needed data and information				
For ongoing market oversight			1.5	1.5
For individual efforts			1.5	1.5
Make information usable (storage, validation and processing)				
For ongoing market oversight			3	4
For individual efforts			2	2
Provide rapid reporting on energy markets to Commission				
Maintain, improve MORe Room			0.5	0.5
Provide real-time analysis of urgent developments, as needed			0.5	0.5
Publish Daily Report			1.5	1.5
Manage Commission closed meeting agenda process			0.5	0.5
Create innovative, professional publications, in print and on web			1.5	2
Publish periodic report with in-depth articles on key topics			1.5	1.5
Coordinate oversight activities with other regulatory agencies (MMUs covered elsewhere)			1	1
Set up, maintain strong communication with academics and think-tanks			0.5	0.5
Conduct outreach with all parts of industry			1	1.5
TOTAL Strategy 3.1.3			*18.5*	*19.5*
TOTAL Objective 3.1			**24**	**25**

Objective 3.2: Assure Pro-competitive Market Structures and Operations

Strategy 3.2.1: Assess market conditions and infrastructure adequacy using objective benchmarks

Activity	Priority	Dates	FTE '03	FTE '04
Develop scorecards on energy markets				
Electric markets in ISOs or RTOs			1.5	0.5
Other electric markets			1	0.5
Natural gas markets			0.25	1
Energy-related financial markets			0.25	1
Track and improve scorecard indicators; publish scorecards			2	2
Establish and report agency performance measures for market performance and oversight (for GPRA)			0.5	0.5
TOTAL Strategy 3.2.1			*5.5*	*5.5*

Strategy 3.2.2: Integrate the Commission's market oversight and the work of market monitoring units

Activity	Priority	Dates	FTE '03	FTE '04
Maintain and further communication with MMUs			3	3
Standardize MMU scorecards and presentations			1	0
Develop integrated roles and responsibilities for MMUs and the Commission			1	0
Set up Commission staff in regions to work with MMUs			4	8
TOTAL Strategy 3.2.2			*9*	*11*

Strategy 3.2.3: Identify and remedy problems with market structure and operations, and periodically review market rules for consistency with long-term market development

Activity	Priority	Dates	FTE '03	FTE '04
Develop, refine and produce Surveillance Report for Commission Meetings			5	5
Develop, refine and publish Seasonal Market Assessment			3.5	3.5
Develop, refine and publish Annual State of the Markets Report			2.5	2.5
Conduct Special Studies			8	10
TOTAL Strategy 3.2.3			*19*	*21*
Note: The reports and studies in this section result from a wide variety of analyses, including economic, engineering, statistical and financial.				

Strategy 3.2.4: Ensure that mergers and consolidations are consistent with pro-competitive goals

Activity	Priority	Dates	FTE '03	FTE '04
Report periodically on competitive conditions in each region			1	1
Provide competitive analysis for indvidual cases			2	2
TOTAL Strategy 3.2.4			*3*	*3*

TOTAL Objective 3.2	**36.5**	**40.5**

Objective 3.3: Remedy Individual Market Participant Behavior as Needed to Ensure Just and Reasonable Market Outcomes

Strategy 3.3.1: Investigate market dysfunctions, exercises of market power and rule violations, and remedy problems through Commission authority

Activity	Priority	Dates	FTE '03	FTE '04
Initiate and conduct timely and effective investigations of market participant behavior			15	16.5
Hold conferences to understand key issues			1.5	1.5
Develop and enforce remedies			1.5	2.5
Recommend policy options as a result of investigations			1	1
Monitor and enforce affiliate standards of conduct			4	5
Examine market trading practices and transactions			3	4
Examine ISO/RTO operations			3	3
Examine transmission access issues, including internet postings			4.5	4.5
Examine operational issues, e.g., outages, TLRs and OFOs			5	5
Examine other market-related behaviors			2.5	2.5
Total Strategy 3.3.1			*41*	*45.5*

Strategy 3.3.2: Use expedited dispute resolution to accelerate processes and minimize expense

Activity	Priority	Dates	FTE '03	FTE '04
Maintain and enhance Hotline			1	1
Develop and market hot line for markets			1	0.5
Resolve disputes from hotline informally			2	3
Act on complaints and requests for declaratory orders			1	1
TOTAL OMOI Strategy 3.3.2			*5*	*5.5*

Strategy 3.3.3: Act swiftly on third party complaints, using litigation before Administrative Law Judges as needed to determine factual issues.

Activity	Priority	Dates	FTE '03	FTE '04
TOTAL Strategy 3.3.3				
TOTAL OMOI Objective 3.3			**46**	**51**

Objective 4.1: Attract, train and retain Staff to Fulfil Strategic Plan

Recruiting Activities			0.5	0.5
Perform personnel services			1.5	1.5
Summer Intern			1	1
Administer Diversity and EEO Programs			0.1	0.1
Receive non-technical training				
Receive training in leadership and management			0.3	0.3
Receive other non-technical training, e.g., ethics, security, EEO, orientation and mentoring, writing, speaking			0.1	0.1
TOTAL OMOI Objective 4			**3.5**	**3.5**
TOTAL OMOI			**110**	**120**

Attachment D

OFFICE OF MARKET OVERSIGHT AND INVESTIGATIONS (OMOI)
Mission and Functions Statement

Mission

The Office of Market Oversight and Investigations serves the public interest by guiding the evolution and operation of energy markets to ensure effective regulation and protecting customers through understanding markets and their regulation, timely identification and remediation of market problems, and assured compliance with Commission rules and regulations.

Functions

1. Acts as principal advisor to the Chairman and Commissioners on issues relating to the Commission's regulation and oversight of energy market structure, energy market performance, and compliance of market participants with the Commission's rules for market activity.

2. Develops policy options and regulatory strategies for consideration by the Chairman and Commissioners.

3. Conducts analytical studies of energy market structures and activities to assess the state of the markets, provide early warning of vulnerable market conditions, and propose policies for improvement.

4. Initiates and executes investigations of possible violations of the Commission's rules, orders, and regulations relating to energy market structures, activities, and participants. Recommends remedies to address violations and, where authorized, pursues remedies through negotiation or litigation.

5. Maintains a forum to informally resolve disputes and advises the Commission on market enforcement and compliance issues.

6. Maintains the Enforcement Hotline to informally resolve disputes concerning any matter subject to the Commission's jurisdiction, including activities that may raise barriers to competition in the natural gas and wholesale electric markets, or impede market-responsive pricing.

7. Conducts market research and develops market models and simulations. Acquires and analyzes public and proprietary information data bases in support of its market oversight and investigatory activities.

8. Reports on the state of energy markets, analyzing market activities and trends, warning of vulnerable market conditions, and recommending changes to the functioning and governance of energy markets. Issues periodic reports of its findings to the Commission and the public.

Market Oversight and Assessment

Mission

Market Oversight and Assessment serves the public by overseeing the Nation's natural gas, electric power and oil pipeline markets and related financial markets, identifying problems and opportunities for those markets, and proposing policy options and regulatory strategies for addressing the issues identified. Assesses the competitiveness, fairness and efficiency of wholesale energy markets. Advises the Commission on the efficacy of its current regulatory policies in light of evolving energy market. Serves as the principal advisor to the Office Director, the Chairman, and the Commissioners on market structure and performance issues. It conducts both periodic and special-purpose studies on energy markets and reports its findings and recommendations to the Commission and the public. Ensures the Commission has the information it needs to oversee markets effectively.

Functions

1. **Scanning.** Identifies important research and policy issues for energy markets with emphasis on anticipating future issues. Monitors developments in the electricity, natural gas, and oil pipeline industries and related financial markets to:
   - Identify trends that may affect what types of market oversight and investigation need to be undertaken and ensure that OMOI is able to meet such changing needs.
   - Identify new technologies that may affect energy markets and analyze their potential effects.
   - Identifies successful regulatory or market solutions to problems in other regulated industries and in energy industries in different countries that may be useful in regulating American energy markets.

2. **Data and Information.** Collects, processes, and disseminates electric, gas and oil information.
   - Determines what information is needed to assess and oversee energy markets. Periodically reviews information needs to guide changes in information collection.
   - Determines what information is needed for specific projects, including those needed to support investigations.
   - Acquires needed data and information from publically available sources when possible and through data collections when necessary; coordinates with all appropriate parties to obtain OMB clearance for data collections.
   - Validates data and information as needed.
   - Processes data and information to make it easy for the rest of OMOI staff to use; designs and creates computer analysis programs and data bases to help use the information.
   - Stores data and information in readily retrievable ways.

3. **Real-time Information Function.** Develops and maintains a real-time information capability that includes the Market Oversight and Resources Room (to obtain real-time

information) and a set of daily and real-time reports (to disseminate real-time information).

4. **Coordination with MMUs.** Works closely with the market monitoring units (MMUs) of Regional Transmission Organizations to ensure that Commission and MMU market oversight are appropriately integrated.

5. **Periodic Reports.** Produces periodic reports on electric power, natural gas and oil pipeline markets and infrastructure and on related developments in financial markets; such reports may include, for example:
   - A market surveillance report to Commissioners (approximately twice a month) reporting major developments in both energy markets and energy infrastructure.
   - A monthly report, giving in-depth discussions of crucial issues arising in the energy industries.
   - A seasonal assessment, providing an outlook for likely and possible developments during the coming season, including early warning of possible problems.
   - An annual State of the Markets Report that summarizes important developments through the year, offers a longer-term perspective on energy markets, and identifies and prioritizes important issues for the future.

6. **Performance Measures.** Develops and maintains objective benchmarks to assess market conditions and infrastructure adequacy; publishes periodic reports cards for different regions using the benchmarks; establishes and reports agency performance measures for market performance and oversight for use with the Government Performance and Results Act.

7. **Specific Studies.** Designs and performs empirical studies to support investigations, and identifies economic and financial issues and potential policies of national importance that require empirical study and conducts such studies.
   - Obtains specific data required for such studies; uses all appropriate analytic techniques, including computer modeling and statistical techniques, economic and engineering analysis, financial analysis of both long term investment issues and risk management issues, an any other techniques that are appropriate.
   - Designs and creates computer analysis programs and data bases for use in such studies.

8. **Outreach.** Participates with market participants on industry standards. Works with other agencies and governments (for example, the Securities and Exchange Commission, the Federal Trade Commission, the Commodities Futures Trading Commission and state Public Utility Commissions), to coordinate energy market oversight.
   - Develops cooperative relationships with other organizations that have a strong effect on market (for example, ratings agencies).
   - Maintains active working relationship with offices within DOE that gather, process and analyze relevant information (for instance, the Energy Information Administration and other policy offices).

- Maintains liaison with other organization doing research on market oversight and regulatory policy, including federal and state agencies, academic institutions and think tanks.
- Reviews outside research on policy and industry issues in order to perform analysis of legislation, regulatory actions, and other factors affecting the energy industry activities regulated by the Commission.
- Gives speeches and represents the Commission at meetings and conferences.

9. **Contracts.** Designs, implements, supervises, and evaluates contracts with outside individuals or organizations to provide information, data, or models needed to implement policy or rate design research. Designs, manages, and evaluates consultant and contractor research projects in conjunctions with the staff's data analyses.

Investigations and Enforcement

Mission

Initiates and executes investigations of possible violations of the statutes administered by the Commission and the rules, orders, and regulations issued thereunder. Recommends remedies to address violations and pursues remedies through negotiation or litigation. Performs audits of industry participants to ensure compliance with the Commission's regulations. Maintains a forum to informally resolve disputes and advises the Commission on enforcement and compliance issues.

Functions

1. Provides overall guidance on general enforcement policy and on all aspects of the enforcement program.

2. Conducts preliminary investigations concerning possible violations of statutes, orders, opinions, or regulations.

3. Advises the Commission on whether to issue formal orders of investigation or take alternative actions such as administrative or judicial enforcement actions, rulemaking, or show cause proceedings.

4. Conducts formal investigations that may include the issuance of subpoenas.

5. Represents the Commission in actions for injunctive and other relief in Federal District Court.

6. Represents the Commission and explains and advocates its legal and policy positions in meetings with industry, other agencies and the public.

7. Appears in administrative adjudicatory proceedings involving alleged violations.

8. Negotiates settlements to obtain compliance with and remedy violations of statutes, regulations and orders.

9. Recommends transmittal of evidence of probable criminal violations to the Department of Justice (DOJ) and other agencies and, if approved by the Commission, coordinates with DOJ and other agencies during the resulting criminal investigation and prosecution, if required.

10. Participates in development of the Commission's strategic plan and recommends regulatory and statutory changes necessary to carry out the enforcement and compliance process.

11. Establishes and maintains liaison with other Federal agencies, state utility commissions and other groups which aid in the enforcement and compliance process.

12. Undertakes any other appropriate enforcement action.

13. Drafts orders, rulemakings and associated memoranda and advises the Commission on matters pertaining to enforcement and compliance.

14. Participates in the development and the analysis of legislation.

15. Maintains the Enforcement Hotline to receive complaints, informally resolve disputes, and provide informed staff opinions and general information to callers concerning any matter subject to the Commission's jurisdiction.

16. Maintains alternative dispute resolution function to informally resolve issues related to barriers to competition in the natural gas and wholesale electric markets, or to impeding market-responsive pricing.

17. In coordination with the Chief Accountant, plans and performs audits of jurisdictional companies in the electric power, natural gas and oil pipeline industries concentrating on materially relevant issues. Reports the audit findings to both the Commission and the affected companies. Recommends corrective actions in cases of error and suggests preventive measures to avoid problems in the future.

18. In coordination with the Chief Accountant, updates and documents audit processes. Develops and documents new types of audits that respond to the needs of the Commission, the industry, and jurisdictional companies. Develops policy and criteria for performing audits, including pilot audits when appropriate.

Division of Management and Communication

Mission

The Division of Management and Communication (DMC) directs the strategic planning, internal and public outreach, information dissemination, and administrative operations of OMOI. DMC is OMOI's point of interface for other Commission Offices and outside entities in these areas.

Functions

1. Coordinates OMOI's strategic management activities.
   - Coordinates with the OMOI Divisions and OED on the development of a Commission-wide strategic plan, OMOI's GPRA compliance, and OMOI's strategic people plan.
   - Prepares OMOI's OMB and Congressional budget requests and justifications.
   - Monitors all budget expenditures and prepares reports for management on allocations, year-to-date expenditures, and forecasts (manage-to-budget).
   - Prepares and updates OMOI's business plan.
   - Manages OMOI's Commission agenda process.

2. Participates in the Commission's outreach program, serving as the focal point of outreach activities on market-based issues.
   - Facilitates partnerships and communications with industry participants such as ISO market monitoring units, academia, consumer groups, industry associations.
   - Facilitates conferences on energy market-based issues for the Commission and interested parties.
   - Delivers speeches and represents the Commission at meetings and conferences.
   - Ensures high-quality products for presentation and distribution at outreach events.
   - Prepares and maintains OMOI's communication plan.

3. Ensures high-quality presentations of all OMOI reports on electric power, natural gas and oil pipeline markets and infrastructure and on related developments in financial markets. These include:
   - A regular Market Surveillance Reports to the Commissioners highlighting major developments in both energy markets and energy infrastructure.
   - A monthly report, featuring in-depth discussions of crucial issues arising within the energy industry.
   - Seasonal assessments, providing an outlook for likely and possible developments during the coming season.
   - An annual State of the Markets Report that summarizes important developments through the year, offers a longer-term prospective on energy markets, and identifies important issues for the future.
   - Other reports as conditions warrant.

4. Provides human resources management and development for the Office.
   - Assesses OMOI's personnel needs and develops plans to meet them.

- Recruits individuals with the skills necessary to fulfill OMOI's mission.
- Provides career development for OMOI employees through training, mentoring, and other programs and activities.

5. Provides administrative support for the Office, including procurement, travel, information technology, and logistics.

Summer 2002 Assessment Report Summary

Office of Market Oversight and Investigations

July 17, 2002

Attachment E

Introduction

Office of Market Oversight And Investigations

- Recent OMOI internal analysis of energy market
- Regional/National Markets
  - Improvements
  - Concerns
- Action Items For OMOI
- Future: seasonal assessments before the relevant cooling or heating season

National Overview

Overall electricity markets fair to good

Market Improvements:

- Regional reserve margins adequate
- Demand responsiveness increased but disappointing
- New electric transmission infrastructure development
- Closer to large regional energy markets; much work remains
- Significant market design improvements

Key Concerns:

- Financial health of market participants
- Potential for extreme weather
- Security threats
- Generator availability
- Possibility of unintended consequences from new market design and rules
- Transmission constraints and service quality

National Overview Cont.

Current OMOI Approach:

- Monitor factors that may affect market performance this summer.
- Coordinate monitoring with others.
- Provide periodic updates to the Commission.
- Provide the Commission with real-time information on major market developments and make recommendations as necessary.

West

Office of Market Oversight And Investigations

More favorable supply and demand conditions. Serious market problems.

Concerns:

- Market friction for trades among sub-regions
- Supply/demand balance
- Declining demand response
- Competition for gas capacity
- Electric transmission infrastructure
- Forecast for above normal temperatures

OMOI Actions:

- Actively monitor electricity markets.
- Recommend that the Commission establish a staff presence with the CAISO MMU.
- Propose a technical conference.

Southeast

Increased merchant presence and improved generation and transmission infrastructure. Competition issues.

Concerns:

- Lack of broad regional markets
- Transmission service quality issues
- Transmission constraints
- Forecast for above normal temperatures

OMOI Actions:

- Monitor progress of Dominion integration into PJM.
- Monitor compliance with the Commission policies.
- Examine patterns of reported negative behavior.
- Develop plan to inform market participants about complaint procedures.

Northeast

Office of Market Oversight And Investigations

Improved generation capacity, transmission infrastructure, and market rules. Load pockets remain.

Concerns:

- Load pockets
- Low margins in Ontario
- Fossil plant availability in New England
- Drought

OMOI Actions (in coordination with NE MMUs):

- Focus on load pockets.
- Monitor possible market power.
- Discern effect of market mitigation on new investment.
- Evaluate market rule changes.
- Examine seams.

Midwest

Strong market fundamentals and active RTO and independent transmission company formation.

Concerns:

- RTO transition
- Transmission schedule curtailments
- MISO export fee

OMOI Actions:

- Monitor impact of utility decisions to join particular RTOs.
- Monitor seams.
- Examine TLRs.
- Focus on the effect of export fees.

Attachment F

OFFICE OF MARKET OVERSIGHT AND INVESTIGATIONS

Hiring and Recruiting

(April 10 – August 16, 2002)

SUMMARY OF HIRING

- 44 On-Board ***Inside*** Hires
- 16 On-Board ***Outside*** Hires
- 60 Vacancies (including 15 – 20 attorney transfers)

120 Total OMOI Staff

SUMMARY OF RECRUITING

- 8 Vacancies have been posted and closed
- 13 Open vacancies (some multiple positions)
- 2 Vacancy announcements being prepared

RECRUITMENT ADVERTISING

- NY Times
- LA Times
- Washington Post
- Houston Chronicle
- San Francisco Chronicle
- Sacramento Bee
- energyJobs.com
- platts.com
- usajobs.com

Committee on Governmental Affairs
EXHIBIT #A-91

Date: 2/25/02 3:43 PM
Sender: Don Chamblee
To: david berick
Priority: Normal
Subject: FERC's FY 2003 funding request for oversight and investigati

Dave -- attached is the response prepared by our budget staff to your question about FERC's request for $7 million and 50 FTEs to enhance its market oversight and investigation capabilities in FY 2003. In checking the figures, we discovered a mistake in the budget narrative. We're actually requesting $5 million, not $7 million for this purpose.

The narrative on page 1 of the budget justification states that our request includes "$7 million and 50 FTEs to enhance the Commission's market oversight and investigation capabilities, and funding to cover the projected cost-of-living increase for employees."

This is not a clearly worded statement. It should have read "7 million and 50 FTEs to enhance the Commission's market oversight investigation capabilities and to cover the projected cost-of-living increase for employees."

Of the requested increase for $7 million and 50 FTE's, $5 million and all 50 FTEs are for enhanced oversight and investigation. The remaining $2 million is to cover the Commission's projected cost-of-living increase in FY 2003.

Whoever cut-and-paste the information from page 1 to page 23 read the poorly worded statement the same way you and I read it and thought the full $7 million was for oversight and investigations. The statement on page 23 is thus incorrect.

The attached response explains how we had to change horses (budget categories) in the middle of the stream after the President designated Pat Wood as Chairman in September of last year. The budget categories used for FY 2003 don't always compare easily with those used in prior years.

The additional $5 million and 50 FTEs requested for enhanced oversight and investigations will be used to staff a newly created Office of Market oversight and investigations. We're going to transfer 50 staff from existing offices to the new office in FY 2002 and use the additional funds and FTEs to build upon this expertise in FY 2003.

The chart included with the budget staff's response compares the Chairman's initiative for FY 2003 with FY 2002 staffing levels.

Hope this is helpful to you. It was to me. Thanks for your question...

<<Response to Question from Dave Berick.doc>>

Response to David Berick
Concerning the Need for an Additional $7 Million and 50 FTEs

During 2001, the Commission was in a state of transition given changes in leadership and economic events, most notably the California energy crisis. Pat Wood, III, took over the Chairmanship in September, with his main priority being an increased emphasis on market oversight and enforcement. Very quickly, the Commission formally outlined a new strategic plan with four main high-level goals, objectives, and strategies.

October saw the beginning of a Commission-wide effort to develop a comprehensive business plan to realize the new goals and objectives. This business plan would have been a guide for FY 2003 budget formulation. However, the business plan had to translate many new concepts into business processes, and was not finalized by the time the budget was submitted. Therefore, we developed the budget from the Chairman's concepts of the level of effort required for each of the new goals. Since we had not been tracking our efforts toward these new goals, we presented FY 2001 and 2002 budgets on a basis comparable to the estimated level of effort required in FY 2003.

The FY 2003 budget requests 250 FTEs for market oversight (Goal 3 of the strategic plan), as shown on pages 1 and 23 of the budget. Of these 250 FTEs, about 100 will be in the new Office of Market Oversight and Investigations (OMOI), handling financial market analysis, data analysis, econometrics, enforcement, auditing, and investigation. The other 150 FTEs will be in other offices covering other related functions, such as litigation and dispute resolution, rulemakings, identification of data requirements, mergers and other corporate applications, and financial auditing.

We plan to build the new office from staff on board and new hires. About 50 staff will transfer to OMOI from the existing Office of Markets, Tariffs and Rates and Office of the General Council. However, many functions of the new OMOI require expertise that is currently limited at the Commission. We need to augment our capabilities in, for instance: intensive market investigations; the details of market operations and how our actions affect the market; risk management and derivatives; and sophisticated market information analysis. We are requesting 50 additional FTEs to build this needed expertise. Attached is a table detailing the Commission's current office structure and how it will change with the added resources in FY 2003.

In addition, page 1 of the budget states the need for $7 million to fund 50 new FTEs and the projected cost-of-living increase for all employees. Of this, $5 million covers the cost of the 50 new FTEs for OMOI, while $2 million covers the Commission's cost-of-living increase. Page 23 incorrectly states the amount needed to build up our market oversight and investigatory capabilities as $7 million rather than $5 million.

OMOI Staffing

Office	FY 2002	FY 2003	Difference
Chairman and Commissioners	31	31	0
Office of Markets, Tariffs, and Rates	365	340	-25
Office of Energy Projects	316	316	0
Office of General Counsel	219	194	-25
Office of Administrative Law Judges	35	35	0
Office of External Affairs	16	16	0
Office of the Secretary	26	26	0
Office of the Chief Information Officer	60	60	0
Office of the Executive Director	132	132	0
Office of Market Oversight and Investigations	**0**	**100**	**100**
TOTAL	**1,200**	**1,250**	**50**

Committee on Governmental Affairs
EXHIBIT #A-92

Memorandum September 6, 2002

TO: Senate Government Affairs Committee
Attention: Dave Berick

FROM: Amy Abel
Specialist in Energy Policy
Resources, Science, and Industry Division

Angele A. Gilroy
Specialist in Telecommunications
Resource, Science, and Industry Division

Mark Jickling
Specialist in Public Finance
Government and Finance Division

Bruce Mulock
Specialist in Government and Business
Government and Finance Division

SUBJECT: Enforcement Activities at Selected Federal Agencies

This memo responds to your request on enforcement activities and personnel levels at several federal agencies to compare with the Federal Energy Regulatory Commission's (FERC) Office of Market Oversight and Investigations (OMOI) July 17, 2002, assessment report.[1] The Office of Market Oversight and Investigations currently has 57 employees (4.7% of FERC's staff), and FERC is recruiting for additional positions. The President's Budget Request for FY2003 asks for 110 full-time equivalent (FTEs) in FY2003 for OMOI, or 8.8% of total FERC staff. The President's Budget Request for FY2003 also asks for $500,000 for FY2003 to contract for outside expertise in this area. FERC has had difficulty recruiting in the areas of energy trading and market oversight so it is unknown whether its current recruiting efforts will be more successful and whether OMOI will be fully staffed in FY2003.

[1] Letter (with attachments) to Sen. Joseph H. Lieberman from FERC Chairman Pat Wood, III. *Re: GAO Report Entitled Energy Markets: Concerted Actions Needed by FERC to Confront Challenges That Impede Effective Oversight.* August 19, 2002.

If you have additional questions, please contact Amy Abel (FERC) at x77239, Angele Gilroy (Federal Communications Commission) at x77778, Mark Jickling (Commodity Futures Trading Commission and Securities and Exchange Commission) at x77784, or Bruce Mulock (Federal Trade Commission) at x77775.

Federal Communications Commission

This section describes the Federal Communications Commission's (FCC) Enforcement Bureau and policies and focuses on common carrier enforcement since the telecommunications sector is most applicable to the energy sector.[2] The FCC's Enforcement Bureau (EB) is the major FCC entity responsible for the enforcement of the 1934 Communications Act and FCC rules, orders, and regulations.[3] The EB was established in November 1999 as the result of an FCC decision to consolidate enforcement functions and personnel that had been spread throughout numerous bureaus within the FCC.[4] This action was taken, according to the FCC, in an acknowledgment of the transition of the FCC from its traditional role of "an industry regulator to a market facilitator."[5]

The EB is currently divided into four divisions: the Telecommunications Consumers Division (TCD); the Market Disputes Resolution Division (MDRD); the Technical and Public Safety Division (TPSD); and the Investigations and Hearings Division (IHD); and 25 regional/district field offices. The TCD enforces consumer-related obligations of common carriers and other telecommunications related entities. MDRD is responsible for negotiating settlements between common carriers, competitors and other carriers relating to competition and other market issues. TPSD is responsible for enforcing public safety and technical issues. IHD is responsible for resolving complaints and enforcing non-technical matters involving broadcast stations, and wireless licensees. This division is also responsible for common carrier audits and for the investigation of suspected or alleged non-compliance of market related requirements. All four divisions are also responsible for resolving complaints in their areas of responsibility. The EB has 25 field offices located in 20 states. The primary function of the field offices is enforcement of technical regulations through on-site investigations, inspections and audits of broadcast stations and other FCC regulated operations.

Examples of the EB's activities include: consumer protection enforcement (e.g. establishing penalties for slamming, junk fax, telephone solicitation violations); common carrier auditing functions and related merger compliance; establishment of a Section 271 Compliance Review Program to more systematically oversee and monitor Bell Operating Company (BOC) performance in states where the FCC has granted Section 271 relief; investigation of possible collocation violations; and settlement of pole attachment

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[2] Unless otherwise noted the information contained in this section was obtained from the FCC's Enforcement Bureau web site http://www.fcc.gov/eb and additional FCC sources.

[3] The FCC does not have the authority to take criminal action against violators but refers such cases to the U.S. Justice Department for prosecution.

[4] Some enforcement duties remain within other bureaus. For example, the Mass Media Bureau continues to have primary responsibility for complaints involving children's programming.

[5] See: FCC press release "FCC Reshapes For The Future - Establishes New Enforcement and Consumer Information Bureaus To Be Effective November 8, 1999." October 26, 1999.

complaints, cable programming tier complaints, and cable technical enforcement.[6]

The FCC is given a variety of enforcement tools through provisions contained in the 1934 Communications Act. Included among these are: the levying of monetary fines, the issuing of consent decrees, and in more extreme cases the revocation of licenses. The FCC also encourages parties to settle complaints outside of the formal process through mediation. For example, the MDRD holds negotiations between carriers to attempt to promote private settlements of disputes before formal complaints are filed. However, as telecommunications markets continue to transition from regulated monopolies to competitive markets, the FCC's enforcement responsibilities take on a larger and more urgent role. The FCC has responded to this transition through internal restructuring (i.e., creating the EB) but is also seeking to further strengthen its common carrier enforcement authority.

The FCC has requested that Congress amend Section 503(b) of the 1934 Communications Act to increase the statutory forfeiture caps for common carriers and lengthen the statute of limitation period for such forfeitures.[7] Under present law, the FCC is limited to fining common carriers up to $120,000 per violation or per day of a continuing violation not to exceed $1.2 million. The FCC must act within one year of the violation(s) at issue. The FCC has requested that Congress amend the Communications Act to increase the maximum fine for a single violation to $1 million and to $10 million for a continuing violation and to lengthen the statute of limitation period.[8]

The FCC's FY2003 budget request, submitted to Congress in February 2002, totaled $278,092,000,[9] including operating costs of $268,327,000.[10] Included in that request was $1,871,000 in increased funding for the Enforcement Bureau to strengthen field enforcement activities. More specifically, the FCC has requested $450,000 in travel funds for field agents and $1,421,000 for technical equipment and vehicles. The FCC has requested funding for 1,975 full-time employees (FTEs) for FY 2003. According to the submitted organizational table, the distribution of FTEs for the proposed FY2003 budget has allocated 279 FTEs, or 14%, to the Enforcement Bureau, an identical figure to the previous budget year. However, FY2003 budget data broken down by activity estimates that 603 FTEs covering several bureaus are dedicated to and associated with enforcement activities.

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[6] Section 271 of the Telecommunications Act prohibits BOC's from offering InterLATA (long distance) services within their service regions unless certain conditions are met.

[7] See: Written statement of Michael K. Powell "Financial Turmoil in the Telecommunications Marketplace: Maintaining the Operations of Essential Communications" before the Senate Committee on Commerce, Science, and Transportation, July 30, 2002.

[8] For example, H.R. 1765, H. R.1542, and S. 2863 contain provisions to increase statutory forfeiture caps and lengthen the statute of limitation period.

[9] The request includes $9,765,000 to fully fund retirement costs and is not part of the operating budget.

[10] See: Federal Communications Commission: FY2003 Budget Estimates to Congress, available at http://www.fcc.gov/Reports/fcc2003budget.html. Please note, FCC restructuring/reorganization is not reflected in these estimates and may affect data.

Commodity Futures Trading Commission (CFTC)

The CFTC enforces federal laws and regulations related to certain forms of derivatives trading, particularly contracts traded on futures exchanges. The CFTC organizes its operations into six divisions: Market Surveillance, Analysis, and Research; Trading and Markets; Enforcement; the Office of Proceedings; the Office of the General Counsel; and Executive Direction and Support.

In FY2001, the Enforcement Division filed 17 civil injunctive actions and 24 administrative proceedings, or 41 actions in all. These cases are described in the CFTC's *FY2001 Annual Report* (available online at www.cftc.gov).

The President's Budget Request for FY2003 asks for $82.8 million in appropriations and 537 staff years. Of this total, the Enforcement Division would receive $22.9 million (27.7% of the total) and 148 full-time equivalent positions (27.6%).

Securities and Exchange Commission (SEC)

The SEC, which enforces federal securities laws, is organized into four divisions: Corporation Finance, Enforcement, Investment Management, and Market Regulation. In FY2001, the Enforcement Division opened 484 enforcement actions: 205 civil injunctive actions, 248 administrative proceedings, and 31 contempt actions.

In the SEC's budget justifications, funding and employment levels are not broken down according to division. The category most directly related to enforcement is "prevention and suppression of fraud," which in the SEC's FY2002 budget accounted for $153.9 million (35.1% of the total $437.9 million) and 983 FTEs (32.8% of the total 2,996). These figures include expenditures and employment at the SEC's regional offices.

The amount of SEC's FY2003 budget is uncertain. The Bush Administration requested $466.9 million for the SEC, an increase of 6.6% over FY2002. In the wake of Enron and other corporate accounting scandals, there was broad support in Congress for a much larger increase in the SEC's budget. P.L. 107-204, the Sarbanes-Oxley Act, authorizes FY 2003 appropriations of $776.0 million. The Senate Appropriations Committee has approved $750.5 million for the SEC. Whatever the final figure, it is likely that the SEC will have substantially more enforcement resources than in past years.

Federal Trade Commission

Created in 1914, the Federal Trade Commission (FTC) enforces some 30 laws enacted by Congress during the past 88 years. As a quasi-judicial, quasi-legislative administrative authority, the FTC enforces laws that prohibit business practices that are anticompetitive, deceptive, or unfair to consumers.

The following testimony underscores the FTC's emphasis on areas of law enforcement:[11]

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[11] Testimony of Timothy J. Muris, Chairman of the Federal Trade Commission, before the (continued...)

> Two areas in the FTC's jurisdiction have become staples of its law enforcement agenda — (1) fighting consumer fraud and deception, and (2) preventing anticompetitive mergers. Since 1995, the FTC has attacked fraud and deception by bringing 1,052 federal court and administrative actions, and obtaining orders for more than $825 million in consumer redress. During the same time period, the FTC reviewed over 26,000 proposed mergers worth a total of nearly $10 trillion, opened about 1,600 formal investigations (issuing "Second Requests" in more than 300 matters), and took enforcement action in over 230 transactions. . . .

For FY2002, the FTC had a budget authority of $155,982,000. This appropriation supports 1,079 full-time-equivalent staff years (FTE), which the agency employs to fulfill its missions (see Table 1.). The initial response of FTC staff in its Congressional Relations Office and the Office of Financial Management to the question of number of the agency's FTEs devoted to "enforcement" was, "All staff are devoted to enforcement; the FTC is an enforcement agency."[12]

When pressed to more narrowly define the breakdown of FTEs devoted to enforcement and non-enforcement activities — and following due consideration — the Office of Financial Management concluded 649 of the FTC's 1,074 FTEs (or 60.4%) were devoted primarily to enforcement activities. More specifically, as shown in Table 1, out of 569 FTEs in the "Consumer Protection Mission," 320 FTEs were considered as "enforcement" by program (Advertising Practices, Marketing Practices, Financial Practices, and Enforcement) while 249 were considered as non-enforcement by program (Consumer & Business Education, Economic & Consumer Policy Analysis, Program Management, and CP Mission Support). And, out of 505 FTEs in the "Maintaining Competition Mission," 329 were considered as "enforcement" by program (Premerger Notification, Merger & Joint Venture Enforcement, Nonmerger Enforcement, and Nonmerger Compliance), while 176 were considered as "non-enforcement" (Antitrust Policy Analysis, Other Direct Mission Resources, and MC Mission Support).[13]

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[11] (...continued)
Subcommittee on Consumer Affairs, Foreign Commerce and Tourism of the Senate Committee on Commerce, Science, and Transportation, July 17, 2002.

[12] James Baker, Federal Trade Commission, Financial Management Division, telephone conversation on Aug. 15, 2002.

[13] "Budget Summary," *Federal Trade Commission*, Fiscal Year 2003 Congressional Justification [http://www.ftc.gov/ftc/oed/fmo/budgetsummary03.pdf], visited August 23, 2002.

Table 1. FTC Staff Devoted to Enforcement Activities

Consumer Protection (CP) Mission	FTEs
Advertising Practices	**65**
Marketing Practices	**146**
Financial Practices	**54**
Enforcement	**55**
Planning & Information	60
Consumer & Business Education	15
Economic & Consumer Policy Analysis	6
Program Management	27
Consumer Protection Mission Support	141
Total CP Enforcement	**320**
Total CP Mission	569

Federal Trade Commission

Annual Performance Plan (FY2002)

Program FTEs

Note: Programs and numbers of FTEs devoted to *Enforcement* appear in bold.

Maintaining Competition (MC) Mission	FTEs
Premerger Notification	**28**
Merger & Joint Venture Enforcement	**208**
Merger & Joint Venture Compliance	**11**
Nonmerger Enforcement	**103**
Nonmerger Compliance	**7**
Antitrust Policy Analysis	7
Other Direct Mission Resources	16
Maintaining Competition Mission Support	125
Total MC Enforcement	**329**
Total MC Mission	505

64%

of the Federal Trade Commission's 1,074 FTEs are devoted to *Enforcement*

Total FTC Enforcement (FTEs)	**649**
Total FTC Mission (FTEs)	1,074

○